Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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William A. Bonnet
Vice President
Government & Community Affairs

September 5, 2007

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Public Utilities Commission of the State of Hawaii
465 South King Street, First Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2006-0386
HECO 2007 Test Year Rate Case – Stipulated Settlement Letter

This letter documents certain agreements between Hawaiian Electric Company, Inc. ("HECO" or "Company"), the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") and the Department of Defense ("DOD") (collectively referred to as the "Parties") regarding matters in this proceeding. Exhibit 1 documents the agreements reached by the Parties on the issues in this proceeding. The Parties have agreed on all but two issues: 1) whether the Company's pension asset should be included in rate base and 2) whether interest synchronization should be used to determine the interest expense deduction for computing the test year income tax expense. The Parties agree that these issues need not be addressed in an evidentiary hearing and that the Parties may file proposed findings of fact and conclusions of law[1] on the pension asset issue only. Exhibit 1 describes these issues in greater detail.

The agreements set forth in Exhibit 1 are for the purpose of simplifying and expediting this proceeding, and represent a negotiated compromise of the matters agreed upon, and do not constitute an admission by any party with respect to any of the matters agreed upon herein. The Parties expressly reserve their right to take different positions regarding the matters agreed to herein in other proceedings.

[1] In Order No. 23612 filed on August 24, 2007, the Commission modified the Parties' proposed Procedural Schedule by requiring the filings of proposed findings of fact and conclusions of law in lieu of opening and reply briefs. As a result, this settlement letter reflects the modified procedural steps reflected in Order No. 23612.

The Parties agree that the rate changes specifically set forth in this Stipulated Settlement result in just and reasonable rates for HECO's regulated electric operations. The Parties shall support and defend this Stipulated Settlement before the Commission. If the Commission adopts an order approving all material terms of this Stipulation, the Parties will also support and defend the Commission's order before any court or regulatory agency in which the order may be at issue. If the Commission does not issue an order adopting all material terms of this Stipulated Settlement, any or all of the Parties may withdraw from this Stipulation, and such Party or Parties may pursue their respective positions on HECO's application without prejudice. For the purposes of this Stipulated Settlement, whether a term is material shall be left to the discretion of the Party choosing to withdraw from the Stipulation.

By Order No. 23612, filed August 24, 2007, the Commission approved the Stipulated Prehearing Order submitted by the Parties on July 23, 2007, with modifications, and amended the Parties' stipulated procedural schedule, approved in Order No. 23442, filed May 17, 2007. The remaining steps in the schedule include:

1. Consumer Advocate and DOD Responses to HECO Information Requests ("IRs")[2]
2. Settlement Proposal to Consumer Advocate and DOD
3. Settlement Discussion
4. HECO Rebuttal Testimonies, Exhibits, and Workpapers
5. Consumer Advocate and DOD Rebuttal IRs ("RIRs") to HECO
6. HECO's Responses to Consumer Advocate and DOD RIRs
7. Submission of Joint Settlement Letter
8. Prehearing Conference
9. Evidentiary Hearing
10. Statement of Probable Entitlement
11. Simultaneous Proposed Findings of Fact and Conclusions of Law[3]
12. Simultaneous Responses to Proposed Findings of Fact and Conclusions of Law[4]

The Parties agree that (a) steps 2, 3 and 7 have been completed, (b) this settlement has eliminated the need for steps 1, 4, 5, 6, 8, and 9,[5] (c) HECO will submit the Statement of Probable Entitlement that reflects the terms of the settlement within five working days following the submission of this settlement letter, (d) HECO will supplement the record with the information provided to the Consumer Advocate and the DOD during the settlement discussions to support the agreements set forth in Exhibit 1 of this settlement letter, to the extent that such

[2] Submission of responses has been deferred pending settlement discussions. See letter dated August 24, 2007 from the Consumer Advocate to the Commission.
[3] See supra note 1.
[4] Id.
[5] The Consumer Advocate and DOD may submit responses to HECO's IRs on the Pension Asset issue.

agreement relied upon the information provided by HECO, (e) as a result of the settlement reached by the Parties, HECO will not be submitting rebuttal testimonies, exhibits and workpapers, (f) the Parties will submit Simultaneous Proposed Findings of Fact and Conclusions of Law on the Pension Asset issue on October 5, 2007, and (g) the Parties will submit Simultaneous Responses to Proposed Findings of Fact and Conclusions of Law on the Pension Asset issue on November 3, 2007.

Under §91-9(d) of the Hawaii Revised Statutes: "Any procedure in a contested case may be modified or waived by stipulation of the parties and informal disposition may be made of any contested case by stipulation, agreed settlement, consent order, or default." As a result of this settlement, the Parties: 1) agree that all of the written testimonies (and exhibits, workpapers, updates and responses to information requests related to such testimonies and updates) in this docket may be submitted without the witnesses appearing at an evidentiary hearing, 2) maintain that it is not necessary to have an evidentiary hearing in this docket, and request that the evidentiary hearing in this docket be canceled, and 3) acknowledge that all identified witnesses are subject to call at the discretion of the Commission, and witnesses called by the Commission shall be subject to cross-examination upon any testimony provided at the call of the Commission. The Parties also agree to waive their rights to (a) present further evidence on the issues, except as provided herein and (b) conduct cross-examination of the witnesses. This waiver shall not apply where a Party deems it to be necessary to respond to evidence or argument resulting from the examination of witnesses or questions asked by the Commission.

The Parties agree that the amount of the Interim Rate Increase to which HECO is probably entitled under §269-16(d) of the Hawaii Revised Statutes is $69,997,000 over revenues at current effective rates[6] (and $127,293,000 over revenues at present rates[7]). The Parties also agree that the final rates set in Docket No. 04-0113 may impact revenues at current effective rates and at present rates, and that the amount of the stipulated interim rate increase will be adjusted to take into account any such changes.

In a subsequent document, the Parties will address the issue of whether there should be a sharing of the risk associated with changes in the price of oil that is reflected in the existing Energy Cost Adjustment Clause. The agreement that is reflected in the instant document is intended to provide HECO will timely rate relief through the Commission's authorization of the stipulated interim rate increase. The Parties' agreement, if any, on the Act 162 matter is not

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[6] Revenues at current effective rates are revenues from base rates plus the interim rate increase approved by the Commission in Interim Decision and Order No. 22050 in HECO's 2005 test year rate case, Docket No. 04-0113, and the interim surcharge for DG trucking and fuel and LSFO trucking authorized in Order No. 23377 in Docket No. 04-0113.

[7] Revenues at present rates are revenues from base rates, but do not include the interim rate increase and interim surcharge revenues.

expected to impact the agreement on the increase to which HECO is probably entitled as set forth in this letter agreement.

Sincerely,

William A. Bonnet
Vice President,
Government & Community Affairs

Enclosure

cc: Division of Consumer Advocacy
Department of Defense

Concurred:

9/6/07

Catherine P. Awakuni
Executive Director
Division of Consumer Advocacy
Department of Commerce and Consumer Affairs

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DOCKET NO. 2006-0386
HECO 2007 TEST YEAR RATE CASE

AGREEMENTS REACHED AMONG HECO, THE CONSUMER ADVOCATE AND THE DEPARTMENT OF DEFENSE

SALES FORECAST AND REVENUES

1. Sales – The Parties agree on the test year sales estimate of 7,720.8 GWh and accept the test year sales by rate schedule and the average number of customers as shown on HECO-201.

ELECTRIC SALES REVENUES

2. See Fuel Expense section for discussion on ECAC revenues.

   In its June 2007 Update, HECO included eight months of revenues in the test year for the interim surcharge for DG fuel and trucking and LFSO trucking costs (at current effective rates) as approved by Order No. 23377 in Docket No. 04-0113. In their respective Direct Testimony filings, both the Consumer Advocate and the DOD proposed to include twelve months of revenues (i.e., $5,358,200) for this surcharge in the test year. (See CA-101, Schedule C-2.) HECO agrees to include $5,358,200 of revenues in the test year, which constitutes twelve months of revenue for the interim surcharge for DG fuel and trucking and LFSO trucking costs.

   Incorporating the above adjustment, the Parties agree that HECO's total electric sales revenues at current effective rates are $1,406,573,200 for the test year.

OTHER OPERATING REVENUES

3. Miscellaneous Other Operating revenues were decreased by $71,000 in the June 2007 Update, HECO T-13, from $1,695,000 to $1,624,000. Amortizations of deferred gains were decreased by approximately $7,000 due to a delay in the sale of the Aiea Park Place property, and Property Licenses and Leases revenues were decreased by $64,000 (from $280,000 to $216,000), as explained in the responses to CA-IR-299, 449 and 450, and the June 2007 Update, HECO T-13. The Consumer Advocate and DOD did not propose any adjustments to the amounts submitted by the Company.

   In addition, in the June 2007 Update for HECO T-8, late payment charges were revised for the updated revenue estimates for the 2007 test year. This resulted in an increase of $2,900 in late payment charges associated with both sales revenues at present rates and sales revenues at current effective rates. See updated HECO-807 on page 8 of June 2007 Update for HECO T-8. The Consumer Advocate did not propose any adjustment to HECO's updates, and also did not consider an estimate of late payment charges for the

Consumer Advocate's recommended increase in revenue requirements. During the settlement discussions, the Parties agreed to resolve their differences as part of a global settlement. As a result, the Parties agree to multiplying a late payment charge factor of .095% to the electric sales revenues at interim rates to determine the late payment charges at interim rates.

Incorporating the above adjustments, the Parties agree for purposes of settlement that HECO's total other operating revenues at current effective rates for the test year are $3,384,000.

<u>EXPENSES</u>

<u>FUEL EXPENSE</u>

4. <u>Fuel Oil and Fuel Related Expense</u>
Test year fuel oil expense and fuel related expense were $536,833,000, and $6,128,000, respectively in HECO's direct testimony. In HECO's response to CA-IR-214 and in HECO T-4 June 2007 Update, fuel oil expense and fuel related expense were increased to $537,767,000 and $6,107,000, respectively. The Consumer Advocate recommended fuel oil expense and fuel related expense estimates of $536,971,000 and $6,100,000, respectively. The DOD reflected HECO's June 2007 Update in its test year expense estimates.

The differences between HECO and the Consumer Advocate were primarily due to the use of different versions of the P-Month production simulation model. As noted in CA-T-2, page 21, lines 6-7, the Consumer Advocate believes that the results of the two models were comparable and reasonable.

As a result, for purposes of reaching a global settlement, the Consumer Advocate and the DOD agree to reflect the results of HECO's production simulation model as presented in response to CA-IR-214 and HECO T-4 June 2007 Update for purposes of determining HECO's test year fuel and fuel related expense. The agreement results in $537,767,000 for fuel oil expense (based on August 2006 fuel prices) and $6,107,000 of fuel related expense for a total test year fuel expense of $543,874,000.

5. <u>ECAC Revenues</u>
In its direct testimony, the Company estimated $563,541,200 of Energy Cost Adjustment Clause ("ECAC") revenues for the 2007 test year (at current effective rates and at present rates). The changes in the Company's fuel oil and fuel related inspection costs and purchased energy costs from the fuel costs embedded in base rates are recovered through the ECAC. At proposed rates, the Company is proposing to include in the ECAC the trucking cost of fuel to the Honolulu Plant and fuel additive costs for HECO generating units. Distributed generating ("DG") fuel, trucking costs and fuel related inspection costs will be included in the ECAC under a new DG energy component, as HECO proposed in Docket No. 04-0113. The Company is also proposing to include a weighted efficiency

factor in its ECAC calculations (in the same manner as HELCO proposed in Docket No. 05-0315), based on fixed efficiency factors for LSFO, diesel and "other" generating units. Because DG units are generally more efficient than other generating units, the Company proposes not to apply a fixed efficiency factor to DG fuel and transportation costs. With respect to Act 162, HECO stated that its ECAC complies with the statutory requirements of Act 162 and the current level of ECAC fuel price risk-sharing is appropriate, and that no change is necessary to the current ECAC risk-sharing approach.

In its June 2007 Update, the Company revised its test year estimate of ECAC revenues to $566,012,100 (at current effective and present rates).

In CA-T-1, the Consumer Advocate agreed that the ECAC should continue to be employed and did not object to the continuation of the ECAC to provide HECO with recovery of changes in energy costs. In CA-T-2, the Consumer Advocate agreed with the Company's proposal to include Honolulu trucking costs, DG fuel and trucking costs and additive costs in the ECAC and to use a three-part sales heat rate for HECO's units. The Consumer Advocate did not oppose HECO's proposal to not subject DG units to a fixed efficiency factor, provided that HECO be required to continue to annually file calibration reports with the Commission and the Consumer Advocate. In Schedule C-3, the Consumer Advocate proposed a reduction of $463,000 to the 2007 test year ECAC revenues (at current effective rates and present rates), based on its calculation of fuel and purchased energy for the test year.

In DOD T-3, the DOD stated that it would be appropriate to use the three efficiency factor approach proposed by HECO and to flow through the actual cost per kWh associated with DG energy without application of a fixed efficiency factor. The DOD accepted the Company's test year estimate of ECAC revenues.

For purposes of the interim rate increase, the Parties agree that the ECAC should continue in its present form. (See discussion on Act 162 below.) Furthermore, as a result of the settlement discussions, the Parties agree on the methodology for calculating the Energy Cost Adjustment Factor ("ECAF"), including the inclusion of fuel additives, fuel trucking, the addition of the "DG Component", and the use of three fixed efficiency factors to replace the single Central Station efficiency factor at present rates, as proposed in HECO T-9. HECO will continue to annually file calibration reports with the Commission and the Consumer Advocate. The Parties agree that the ECAF at present rates is 7.340 cents/kwh, and that the ECAF at proposed rates is 0.000 cents/kwh. (See HECO T-9 Attachment 7.) This factor incorporates the $620,000 adjustment to the test year purchased power expense projection as explained below.

Applying the 7.340 cents/kwh ECAF to the agreed upon test year forecasted kwh sales projection results in ECAC revenues of $566,706,800 (at present rates and current effective rates). The Parties agree that the sales heat rates used in the ECAF as fixed efficiency factors at proposed rates are:

LSFO plants:	0.011143 mbtu/kwh
Diesel plants:	0.034955 mbtu/kwh
Other plants:	0.011209 mbtu/kwh
Weighted average:	0.011209 mbtu/kwh

Act 162

In accordance with Act 162, 2006 Session Laws of Hawaii ("Act 162"), the Commission added the following issue in Order No. 23612, issued August 24, 2007: "Whether HECO's ECAC complies with the requirements of HRS §269-16(g)?" Thus, the Parties have not yet determined how to develop the ECAC design factors identified in HRS §269-16(g). The Parties are continuing discussions with respect to the final design of the ECAC to be approved in the final decision and order and will either submit a further stipulation regarding this matter, or address the matter in their respective proposed findings of fact and conclusions of law. The Parties agree, however, that their resolution of this issue will not affect their agreement regarding revenue requirements, and that it is appropriate for the Commission to issue its interim rate order based on the stipulated revenue requirements.

POWER PURCHASE EXPENSE

6. Test year purchased power expense was $386,108,000 in direct testimony and increased to $386,872,000 in HECO T-5 June 2007 Update. In direct testimony, the Consumer Advocate recommended a test year purchased power expense estimate of $387,518,000, which is $646,000 more than HECO's June 2007 Update. In support of its recommendation, the Consumer Advocate noted that the AES base fuel component for one boiler in the month of October was not calculated in HECO's direct testimony and in its June 2007 Update estimates. During the settlement discussions, HECO agreed with the Consumer Advocate that there was an error in HECO's workpapers and recalculated its AES energy payment. As a result, HECO proposed to increase its AES energy payment by $620,000. See HECO T-5, Attachments 1 and 2 for the calculations supporting the $620,000 adjustment. After the above adjustment, there remained a difference of $26,000 between HECO and the Consumer Advocate.

For purposes of settlement, the Consumer Advocate and the DOD agree to reflect HECO's purchased power expense of $386,872,000 as provided in HECO T-5 June 2007 Update, plus an additional $620,000 to correct the AES energy charges related to the AES base fuel component in the month of October, for a total purchased power expense of $387,492,000 for the test year.

OTHER PRODUCTION O&M EXPENSES

7. Test year production O&M expenses were estimated to be $68,222,000 in HECO's direct testimony, which was increased by a net $1,855,000 to $70,077,000 in the Company's HECO T-6 June 2007 Update, filed on June 29, 2007, and HECO T-6 June 2007 Supplemental Update, filed on July 25, 2007. The Consumer Advocate's estimate was

$66,436,000, or $3,641,000 lower than HECO's T-6 June 2007 Update, due to seven adjustments that are discussed below (see discussion in subparagraphs a through h). The DOD also proposed one adjustment to reduce production security services expense by $117,000 (see discussion in subparagraph i). As a result of the settlement reached on these eight issues as described below, the Parties agree to reduce HECO's June 2007 Update estimate of $70,077,000 by $2,479,000, resulting in revised test year production O&M expenses of $67,598,000.

In addition, all Parties agree to the Company's production inventory of $6,678,000 as presented in direct testimony.

a. <u>Environmental 316(b) Expense Update</u>
In HECO T-6 June 2007 Update, HECO proposed to increase its 2007 test year production operations non-labor expense by a 3-year normalized amount of $1,006,000 to comply with the EPA's Clean Water Act Section 316(b) Phase II rules. In CA-T-1 (Schedule C-6), the Consumer Advocate proposed a $175,000 adjustment reducing HECO's June 2007 Update expense estimate to $831,000. For purposes of a global settlement, the Company agrees to reflect the Consumer Advocate's proposed adjustment, resulting in $831,000 of environmental expenses for the test year.

b. <u>Generation (Competitive) Bidding Division Expense Update</u>
In HECO T-6 June 2007 Update, the Company increased its Generation Bidding Division non-labor expense by $243,000. In CA-T-1 (Schedule C-7), the Consumer Advocate proposed a $243,000 reduction to allow only the $175,000 level of non-labor expenses initially estimated by HECO to be incurred in 2007, and cited the Company's actual spending through May 2007 as support for its proposed adjustment. During the settlement discussions, the Company provided additional support for its updated estimate of 2007 non-labor costs for this Division , and the reasons for its higher normalized test year estimate. The Consumer Advocate did not dispute that additional future outside services expenses may be incurred by HECO to support competitive bidding, but objected to the inclusion of any costs that are expected to be incurred after 2007 in the test year estimate on the grounds that such inclusion would violate the Test Year concept. As part of the overall settlement of issues impacting revenue requirements, the Company agrees to reduce its Generation Bidding Division non-labor expense by $243,000, resulting in a total expense projection of $175,000 for the test year.

c. <u>Production O&M Labor Adjustment</u>
In CA-T-1 (Schedule C-4), the Consumer Advocate proposed a $953,000 reduction to production O&M labor expense but stated its willingness to consider equitable revisions to its labor adjustment for the maintenance accounts if HECO could show clear evidence that it requires additional supplemental labor to meet normal, on-going maintenance requirements because of the Company's inability to fill vacant positions in the Maintenance Division. During settlement negotiations, HECO provided additional information to address the Consumer Advocate's stated concern. After considering the supplemental maintenance labor cost information provided by the Company and the

adjustments proposed for deferred station maintenance as described below, the Consumer Advocate accepted the Company's position that no adjustment to HECO's Production O&M labor expense is required. See HECO T-6, Attachment 3, August 2007 Supplement.

d. Deferred Station Maintenance List Projects Adjustment
In CA-T-1 (Schedule C-5) the Consumer Advocate proposed a $1,813,000 reduction to production O&M expense to eliminate the costs associated with certain lower priority power station maintenance projects that were included in HECO's test year forecast. The proposed adjustment was based on HECO's representation in response to CA-IR-240, 241, and 242 that certain projects on the Kahe Station, Waiau Station and Honolulu Station priority lists would not be done in 2007. During the settlement discussions, HECO opposed the adjustment, and provided additional information on unbudgeted priority list items that have been or will be done in 2007. After reviewing the material, the Consumer Advocate continued to assert that its proposed adjustment is reasonable, citing the Company's discretion to proceed with station maintenance work, actual spending through July 2007, and the Consumer Advocate's reconsideration of its Production labor expense adjustment (see discussion in subparagraph c). As part of the overall settlement of the issues impacting the test year revenue requirements, the Company accepts the Consumer Advocate's $1,813,000 adjustment to reduce the deferred station maintenance expense estimate for the 2007 test year.

e. Production Department Research and Development Adjustment
In CA-T-1 (Schedule C-8), the Consumer Advocate (1) removed funding for the Electric Shock Absorber ("ESA") from test year expense estimate based upon the uncertain status of future activities and costs related to this project, and (2) reduced the budgeted amounts for the other R&D spending initiatives (which it assumed was $754,000[1]) by one third, offset by HECO's actual spending through April 2007 ($30,656), to recognize that one third of the year has passed with very little activity or spending to-date, and the apparent uncertainties and potential delays in actual activities and expenditures. The net effect was to reduce the $935,000 amount proposed by HECO by $442,000 resulting in a test year expense estimate of $493,000. Upon consideration of the additional information provided by HECO during the settlement discussions describing HECO's additional funding commitments, the Consumer Advocate indicated its willingness to reduce the Schedule C-8 adjustment of $442,000 to a revised reduction of $225,000. (See HECO T-6, Attachment 5, August 2007 Supplement.) For purposes of settlement, the Company

[1] $754,000 + $221,000 = $975,000, not $935,000. Based on HECO-629, the Consumer Advocate assumed that $40,000 for Sun Power for Schools expenses were included in the test year estimate. However, the 2007 budget (and, thus, the 2007 test year estimate) also includes a $40,000 credit, so that the net amount included in the test year was zero. See response to CA-IR-80. If the inclusion of the $40,000 is backed out of the Consumer Advocate's proposed adjustment, the Consumer Advocate's adjustment would be reduced from ($442,000) to ($428,000).

accepts the Consumer Advocate's compromised $225,000 adjustment,[2] which reduces HECO's test year production R&D expense estimate to $710,000.[3]

f. Expiring Software Amortization

In Direct Testimony, HECO proposed to include $108,000, which represents the amortization through September 2007 of prepaid software expense that was paid to MINCOM, HECO's Ellipse software vendor. As noted in CA-T-3, the amortization period for this expense was reflected in the Stipulated Settlement Letter accepted by the Commission for purposes of Interim Decision and Order No. 22050 in HECO's 2005 test year rate case. Although this software amortization would be recorded for nine months in 2007, the Consumer Advocate proposed that the $108,000 of amortization be eliminated from the test year revenue requirement, noting that the amortization would not continue beyond September 2007. As shown on CA-101, Schedule C, page 3, the Consumer Advocate allocated the $108,000 adjustment as follows:

Production	$ 6,000
Transmission	$ 3,000
Distribution	$ 11,000
A&G	$ 88,000
Total	$108,000

For purposes of settlement, the Company accepts the Consumer Advocate's adjustment and will remove the MINCOM amortization expenses from HECO's test year expense estimates for the above accounts.

g. Abandoned Projects Normalization Adjustment

In Direct Testimony, HECO proposed to include an estimate of $224,000 for abandoned project costs in the test year revenue requirement. In CA-T-3 (Schedule C-19), the Consumer Advocate proposed a $122,000 adjustment to reflect an average of the actual abandoned projects costs for 2001 through 2006, without escalating the costs to 2007 dollars, and excluded the costs related to the Barbers Point NAS privatization costs. As noted on CA-101, Schedule C, page 4, the Consumer Advocate allocated its proposed $122,000 adjustment to reduce HECO's test year estimates as follows:

Production	$ 9,000
Transmission	$ 3,000
Distribution	$104,000
Customer Accounts	$ 7,000
A&G	($ 2,000)
Total	$122,000

The DOD did not propose any adjustment in this area.

[2] The Consumer Advocate's compromise adjustment was based on allowance of $25,000 for disposal of damaged equipment for the ESA, taking into account the range of disposal costs estimated by HECO, and $36,000 for recurring renewable energy funds, taking into account actual expenditures through July 2007 and anticipated HNEI billings.

[3] $935,000 minus $225,000 equals $710,000.

As a result of the settlement discussion, the Consumer Advocate agreed to reduce its total abandoned projects normalization adjustment to $94,000. Using the distribution between functional accounts provided by HECO T-10, Attachment 4, the Consumer Advocate's revised abandoned project cost adjustment of $94,000 is reflected as follows:

Production	$ 18,000
Transmission	$ 10,000
Distribution	$ 51,000
Customer Accounts	$ 13,000
A&G	$ 2,000
Total	$ 94,000

For purposes of settlement, the Company accepts the Consumer Advocate's revised adjustment and allocation as noted above.

h. <u>Security Services Expense Adjustment</u>
In DOD T-1 (DOD-116), the DOD proposed to reduce the Company's security services expense by $117,000. The DOD's adjustment was based on HECO's security services expense through June 2007, which DOD annualized and deducted from HECO's test year estimate. The Company provided additional information in support of its position that the funds for annual security services, as originally estimated at $730,280 are expected to be spent in 2007, and proposed that no adjustment be made. (See HECO T-6, DOD Attachment 1, August 2007 Supplement.) For settlement purposes, the DOD agrees to no adjustment to HECO's security services expense.

<u>TRANSMISSION AND DISTRIBUTION (T&D) O&M EXPENSES</u>

8. Test year transmission O&M expenses were estimated to be $10,491,000 in direct testimony, which was decreased by a net $113,000 to an updated total of $10,378,000 in the Company's HECO T-7 June 2007 Update, filed on June 29, 2007. Test year distribution O&M expenses were estimated to be $24,722,000 in direct testimony, which was increased by a net $226,000 to an updated total of $24,948,000 in the Company's HECO T-7 June 2007 Updated, filed on June 29, 2007. The result is a test year estimate of $35,326,000 for T&D. After reflecting the adjustments proposed by HECO in the June 2007 Update, the Consumer Advocate proposed adjustments amounting to $509,000 resulting in a test year T&D estimate of $34,817,000, consisting of $10,258,000 and $24,559,000 for transmission and distribution, respectively. The $509,000 adjustment proposed by the Consumer Advocate consisted of the following: $388,000 (Schedule C-13), $14,000 (Schedule C-15) and $107,000 (Schedule C-19) to reduce T&D O&M labor expenses, remove the expiring MINCOM amortization and normalize the abandoned projects expense estimate, respectively. The DOD did not propose any adjustment to T&D O&M expenses. As a result of the settlement reached on the three issues as described below, the Parties agree on a reduction of $391,000 to HECO's June

2007 Update, resulting in a revised test year estimate of $10,272,000 for transmission O&M expenses and $24,663,000 for distribution O&M expenses.

In addition, all Parties agree to the Company's T&D inventory of $6,160,000 as presented in direct testimony.

a. T&D Payroll Expense Adjustment

In CA-T-3 (Schedule C-13), the Consumer Advocate proposed a T&D O&M labor expense adjustment of $388,000 to reduce HECO's test year expense estimate for 14 employee positions. The proposed adjustment was based on the beginning of test year actual T&D Employees (December 31, 2006) and HECO's end of year estimate (December 31, 2007) of T&D employee levels. During the settlement discussions, the Company provided information regarding the hiring of employees and unbudgeted temporary hires in January of the test year and proposed a lower T&D labor expense adjustment. After reviewing the information the Consumer Advocate agreed to revise its adjustment to reflect the compensation for 11 employees (versus the 14 upon which the Consumer Advocate based its $388,000 adjustment). The result is a revised adjustment of $316,000. The adjustment reduces HECO's 2007 Update estimates by $93,000 and $223,000 for transmission and distribution O&M labor, respectively (see HECO T-14, Attachment 1(B)). For purposes of settlement, HECO agrees to accept the Consumer Advocate's revised adjustment.

b. Expiring Software Amortization

As discussed in subparagraph 7.f. above, in CA-T-3 (Schedule C-15), the Consumer Advocate proposed reductions of $3,000 and $11,000 to transmission O&M non-labor expenses and distribution O&M non-labor expenses, respectively to eliminate the MINCOM amortization fee which will terminate in September 2007. For purposes of settlement, the Company accepts the Consumer Advocate's adjustments.

c. Abandoned Projects Normalization Adjustment

As discussed in subparagraph 7.g. above, in CA-T-3 (Schedule C-19), the Consumer Advocate proposed reductions of $3,000 and $104,000 to transmission O&M and distribution O&M non-labor expenses, respectively for abandoned projects. As a result of the settlement discussions, the Parties agree to reflect a revised reduction of $10,000 and $51,000 to the transmission and distribution expense estimates, respectively.

CUSTOMER ACCOUNTS

9. Test year customer accounts expenses, excluding allowance for uncollectible accounts, were estimated at $12,020,000 (HECO-801) in HECO's direct testimony. The Company's test year estimate decreased to $11,929,000 in the June 2007 Update for T-8, filed on June 29, 2007 (updated HECO-801, pages 9 and 10 of the June 2007 Update for T-8), which reflected a reduction for Customer Records and Collections of $91,000. In the response to CA-IR-428.d, HECO proposed a further reduction of $66,900 for

non-labor expenses for temporary services. The result is a revised test year estimate of $11,862,100.

In its direct testimony, the Consumer Advocate recommended a test year customer account expense estimate of $11,729,000 resulting in a difference of $133,100 from HECO's revised test year estimate of $11,862,100. The differences resulted from the following:

- The Consumer Advocate reflected an adjustment of $88,000 to reduce the Company's direct testimony estimate, as opposed to the $91,000 proposed in HECO's June 2007 update, resulting in a $3,000 difference.
- In addition, the Consumer Advocate proposed an adjustment of $85,986 (rounded to $86,000) to reduce expenses for temporary services (Schedule C-9), which is $19,086 (rounded to $19,100) more than the $66,900 reduction proposed by HECO in its response to CA-IR-428.d.
- The Consumer Advocate also proposed an adjustment to exclude $110,000 for Bank of Hawaii fees (Schedule C-9).
- The Consumer Advocate proposed a $7,000 adjustment to normalize the abandoned project costs included in the test year revenue requirement, as discussed in subparagraph 7g. above.

The DOD did not propose any adjustments for customer accounts.

For purposes of settlement, HECO will accept the Consumer Advocate's adjustments for temporary services and Bank of Hawaii fees and reflect the Company's June 2007 Update revision (i.e., the $91,000). In addition, as noted above, the differences regarding the adjustment to normalize the test year abandoned project costs were resolved.

As a result, the Parties agree on a test year estimate of $11,720,000 for customer accounts expense, excluding the allowance for uncollectible accounts.

ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS

10. In the June 2007 Update for T-8, HECO revised its estimates for uncollectible accounts expense due to updated revenue projections for the 2007 test year. The uncollectibles factor was not changed. The estimates of uncollectible accounts expense increased by:

1. $3,000 from $1,358,000 to $1,361,000, at present rates; and
2. $2,000 from $1,411,000 to $1,413,000, at current effective rates.

The changes in the test year estimates are reflected on the updated HECO-805 (page 7 of the June 2007 Update for T-8).

The Consumer Advocate disagreed with HECO's methodology for calculating the uncollectible accounts expense based on a percentage of electric sales revenues. The

Consumer Advocate proposed an uncollectible accounts expense of $727,420 (Schedule C-9) based on the average of the actual 12-month cumulative net write-off as of December 2002, December 2003, December 2004, December 2005 and December 2006.

The allowance for uncollectible accounts was not an issue in the DOD's testimony.

During the settlement discussions, HECO proposed an allowance for uncollectible accounts expense of $970,000. The $970,000 was calculated by HECO using five years of data (from July 2002 to June 2007, instead of the 10 years of data used in direct testimony) to calculate an estimated net write-off percentage for the test year of .0719% (see HECO T-8, Attachment 1), which was applied to revenues at present rates ($1,348,635,000 x .0719% = $970,000).

During the settlement discussions, the Parties could not reach agreement on the method of calculating the test year uncollectible accounts expense. For purposes of settlement, however, the Parties agree to reflect $970,000 as a fixed uncollectible accounts dollar expense amount, with no further adjustment for assumed increases in uncollectibles associated with interim rate increases or the proposed revenues arising from the present docket.

<u>CUSTOMER SERVICE</u>

11. Test year customer service expenses were estimated to be $7,176,000 in direct testimony, HECO T-9, which was increased by a net of $94,000 to an updated total of $7,270,000 in the Company's HECO T-9 June 2007 Update, filed on June 15, 2007. The Consumer Advocate recommended a test year expense estimate of $5,594,000, resulting in a reduction of $1,676,000 to the Company's June 2007 Update estimate. The adjustments proposed by the Consumer Advocate are comprised of the following:

- $101,000 (Schedule C-10) for payroll expense,
- $641,000 (Schedule C-11) for reclassification of DSM expenses, and
- $934,000 (Schedule C-12) for informational advertising.

The DOD proposed no adjustments in this area.

As a result of the settlement discussions, the Parties agree to an adjustment of $1,562,000, as described below. A portion ($182,000) of the adjustment reflects the overhead costs (i.e., corporate administration, employee benefits, and payroll taxes) associated with the reclassification of DSM Program expenses, as discussed in subparagraph 11.b below. For purposes of this settlement, these overhead costs are spread to the appropriate accounts; $36,000 to corporate administration (see subparagraph 12.i), $120,000 to employee benefits (see subparagraph 12.d), and $26,000 to payroll taxes (see paragraph 15). The remaining adjustment of $1,380,000 was applied to HECO's June 2007 Update estimate of customer service expense, resulting in a revised test year estimate of $5,890,000.

a. Payroll Expense Adjustment

In CA-T-1, the Consumer Advocate proposed a Customer Service labor expense reduction adjustment of $101,000 (Schedule C-10). The proposed adjustment was based on the same average staffing methodology and rationale proposed for the T&D labor expense adjustment. During the settlement discussions, the Company provided information regarding specific positions that were filled in January of the 2007 test year. As a result, the Company proposed a lower adjustment, which was partially accepted by the Consumer Advocate. The accepted changes in the calculation of average employees decreased the Consumer Advocate's recommended expense reduction of employees from 2.5 to 2.0. For purposes of settlement, the Parties agree to a labor expense reduction of $85,000 (see HECO T-14, Attachment 1(A)).

b. DSM Program Expense Adjustment

In CA-T-1, the Consumer Advocate proposed a Customer Service expense adjustment of $641,000 (Schedule C-11) to remove the test year proposed level of DSM Program Costs, other than the "CIDLC" and RDLC" load management programs, from base rates and recover such costs through the IRP Clause effective with the implementation of new base rates for HECO in this docket. The Company agreed with the Consumer Advocate's proposed recommendation to reclassify certain DSM labor costs to the IRP Clause, but proposed a smaller adjustment.

For purposes of settlement, HECO and the Consumer Advocate agree to an adjustment of $543,000, which includes $361,000 in labor and $182,000 of on costs as shown on HECO T-9 Attachment 8. These costs will need to be recovered prospectively through the DSM component of the IRP cost recovery provision ("DSM Surcharge") effective with the implementation of new rates in this Docket and continuing beyond the transition date (in or about January 2009) to be identified by the Commission in the docket it intends to open to transition DSM programs to a non-utility market structure so as to track actual HECO expenses changing as a result of such market structure. The DSM Surcharge, through which the public benefits fund will be collected, will be administered by the utility and the extent to which HECO resources are required to administer the fund or to ensure a smooth transition, as required by Decision and Order No. 23258, to a non-utility structure is presently unknown. The Consumer Advocate understands that transition issues may be encountered that will impact the timing of the actual HECO labor cost reductions arising with third party administration. The difficulty in predicting future needs for HECO assistance during transition is why the Consumer Advocate believes that surcharge recovery is important at this time, to provide flexibility and more precise regulatory accounting and recovery of actual costs that are expected to change in the future. The Department of Defense has not proposed any adjustments in this area.

In the June 2007 Update for HECO T-9, HECO increased labor cost by $75,000 associated with the addition of two regular HECO employees (CEP Analyst and C&I

Engineer) into base rates. (June 2007 Update, HECO T-9, pages 1 and 3.) Inclusion of these employees in base rates was based on the EE Docket D&O, which states, "...labor costs shall be recovered through base rates and all other DSM-related utility-incurred costs shall be recovered through a surcharge." The Consumer Advocate proposed that the labor expenses for these two employees be reclassified to be recovered in the IRP Clause. The Company accepts the Consumer Advocate's recommendation for purposes of settlement and has reclassified the labor associated with these two employees to be recovered through the IRP Clause as discussed above. The Department of Defense has not proposed any adjustments to the Company's proposal.

c. Informational Advertising Expense

In CA-T-1, the Consumer Advocate proposed a reduction in test year informational advertising of $934,000 (Schedule C-12). The Consumer Advocate contends that such increased advertising spending has not been proven to be necessary or cost-effective. The Department of Defense did not propose any adjustment in this area.

As part of the overall settlement on revenue requirements, HECO has accepted the Consumer Advocate's recommendation.

ADMINISTRATIVE AND GENERAL (A&G)

12. Test year A&G expenses were estimated to be $72,007,000 in direct testimony, HECO T-10, which was increased by a net of $3,779,000 to an updated total of $75,786,000 in the Company's HECO T-10 June 2007 Update, filed on July 23, 2007. The Consumer Advocate recommended a test year expense estimate of $68,555,000, resulting in a reduction of $7,231,000 to the Company's June 2007 Update estimate. The adjustments proposed by the Consumer Advocate are comprised of the following:

- $596,000 (Schedule C-16 and C-17) for payroll expense,
- $330,000 (Schedule C-20) for Public Affairs consultant and service and community process activities,
- $535,000 (Schedule C-21) to normalize the costs for the Ellipse Migration,
- $254,000 (Schedule C-22) to reflect the Employee Benefits associated with the recommended labor adjustments proposed in Schedules C-16 and C-17,
- $(2,000) (Schedule C-19) to normalize the abandoned project costs,
- $375,000 (Schedule C-14) to normalize the R&D expense,
- $88,000 (Schedule C-15) to remove the expiring MINCOM amortization, and
- $5,055,000 (Schedule C-18) to remove the amortization of the pension asset.

As a result of the settlement discussions, the Parties agree to a revised test year estimate of $69,187,000, which is $6,599,000 less the HECO's June 2007 Update estimate and reflects the settlement of these nine issues as described below, as well as the removal of corporate administration and employee benefits expenses (see subparagraphs 12.i and12.d, respectively) associated with the reclassification of DSM Program expenses for the six Customer Service employees removed from base rates (to be recovered through the IRP Clause (see paragraph 11 and subparagraph 11.b).

a. Payroll Expense Adjustments for A&G Accounts

The Consumer Advocate initially proposed A&G labor expense adjustments of $596,000 (Schedules C-16 and C-17) in CA-T-3. The proposed adjustments were based on the same methodology and rationale for the proposed T&D Payroll Expense Adjustment (CA-101, Schedule C-13) and were based on the average of the beginning of year actual A&G employees (December 31, 2006) and HECO's end of year forecast (December 31, 2007) employee levels.

During the settlement discussions, the Company noted and the Consumer Advocate agreed that the proposed $108,660 adjustment to reduce the labor expenses for Responsibility Area ("RA") PNP, Regulatory Affairs should not be included. Because the Company had already reflected an increase of staff positions occurring in the middle of the test year, test year labor expenses were estimated for a test year average employee count identical to that calculated by the Consumer Advocate (see HECO T-14, June 2007 Update, revised 6/29/07, page 3 of 4). As a result, no difference exists between the Consumer Advocate's and HECO's estimates of average test year employee counts for RA PNP and the $108,660 labor expense adjustments proposed by the Consumer Advocate in C-16 is not required (see HECO T-14, Attachment 1(C)).

HECO also provided information regarding the positions that were filled in January of the test year by employees or HECO temporary employees and outside contractors for the other RAs. The Company proposed adjustments to reduce the adjustments proposed by the Consumer Advocate in Schedules C-16 and C-17. Based on the information provided, the Consumer Advocate acknowledged the Company's claim that the average employees using the updated information decreased the Consumer Advocate's recommended reduction of employees in Schedule C-16 from 14.5 to 7.0, and in Schedule C-17 from 3.0 to 2.0, but did not concur with the other representations of the Company. For purposes of settlement, the Parties agree to a total A&G labor reduction of $232,000 (as opposed to the $487,340 adjustment proposed by the Consumer Advocate in Schedules C-16 and C-17) (see HECO T-14, Attachments 1(C) and 1(D)).

b. Public Affairs

In direct testimony, HECO included in its test year estimate for outside services general (Account 921) costs of $660,000 for Public Affairs consultant, specific service and community process activities. The Consumer Advocate (Schedule C-20) and the DOD recommended a downward adjustment of $330,000 or one-half of the Company's test year estimate.

For purposes of settlement, the Parties agreed on the test year estimate of $570,000, reflected a decrease of $90,000 for outside services general (Account 921). As a condition to this agreement, the Company agrees to provide the Consumer Advocate with documentation by January 31, 2008 (i.e., presumed to be prior to the issuance of a final decision and order) that the additional $240,000 for Company's two critical projects (greenhouse gas emission research project and seabird mitigation measures) was actually spent in 2007 and that the Company's 2007 expenditures in this area will approximate $750,000[4], including the $240,000.

c. Ellipse Migration

The Company's test year estimate for the non-labor Ellipse Unix migration costs increased from $509,000 (See HECO T-10, page 21) to $854,000 as presented in HECO's responses to CA-IR-392, CA-IR-438 and CA-IR-440. The Consumer Advocate proposes to "normalize" the Ellipse Unix Migration cost for 2007 over three years, resulting in a downward adjustment of $535,000 (Schedule C-21). The DOD did not propose any adjustment in this area.

For purposes of settlement, the Company agrees to reduce the Ellipse Unix Migration costs included in the test year by $535,000 as proposed by the Consumer Advocate, resulting in a normalized test year estimate of $319,000.

d. Employee Benefits

HECO's test year estimate for employee benefit expenses (Account Nos. 926000 and 926010) is $27,636,000, as presented in HECO-1201. The Company's estimated employee benefit expenses for the test year was increased by $3,654,000 for an updated total of $31,290,000. See HECO's June 2007 update (Supplemental) for HECO T-12.

In Exhibit CA-101, Schedule C-22, the Consumer Advocate proposed to reduce HECO's revised forecast of employee benefit expenses by $254,000 to reflect the employee count reduction proposals made for the T&D, Customer Service, and other departments that charge to A&G accounts. Based on the Parties' agreement on the test year headcount reduction of 22, associated employee benefits are reduced by $103,000 in Account No. 926010, which was accepted by the Parties for purposes of settlement (see HECO T-14, Attachment 1(E)). In addition, HECO's estimate for employee benefits expenses is reduced by $120,000, to reflect the reclassification of DSM Program expenses for the six Customer Service employees removed from base rates (to be recovered through the IRP Clause) as discussed in paragraph 11 and subparagraph 11.b. This reduction is agreed to by the Parties.

e. Abandoned Project Costs

As discussed in subparagraph 7.g. above, for purposes of settlement, the Parties agree on the test year estimate for abandoned project costs of $130,000, as shown on HECO T-10, Attachment 1, which provides the allocation of abandoned costs by block of accounts.

[4] The Company clarified with the Consumer Advocate that it expects to spend approximately $750,000 in 2007 in this area.

f. Miscellaneous Administrative and General (A&G) Expenses

Test year miscellaneous A&G expenses were estimated to be $7,487,000 in direct testimony, which was increased by a net $195,000 to an updated total of $7,682,000 in the Company's HECO T-13 June 2007 Update, filed June 15, 2007. In direct testimony, the Consumer Advocate proposed adjustments of $375,000 (Schedule C-14) for research and development ("R&D") and $88,000 for expiring MINCOM software amortization expenses as discussed in subparagraph 7.f. above. The DOD also proposed adjustments of $375,000 to reduce R&D expenses and $61,000 for Edison Electric Institute Membership dues. As a result of the settlement discussions, all Parties agree to a revised estimate of $7,239,000 for Miscellaneous A&G expenses, which includes the settlement of these three issues as described below.

R&D

In the Company's direct testimony, HECO T-13, R&D expenses were estimated at $2,591,000 for EPRI dues and multiple R&D projects. This amount was increased by $173,000 to a total of $2,764,000 in the Company's June 2007 Update. Both the Consumer Advocate and DOD did not propose any adjustment to the EPRI dues of $1,608,000 in the test year. However, for the non-EPRI R&D project amount, the Consumer Advocate and DOD proposed a "normalization" adjustment of $375,000 based on a three year average (including the test year) of R&D expenses (CA-101,Schedule C-14). During the settlement discussions, the Company provided further information (see HECO T-13, August 2007 Supplement) to support its proposed non-EPRI R&D expense projection of $1,156,000 ($2,764,000 less $1,608,000). For purposes of settlement, the Company proposed a total reduction of $300,000 based on projected expenditures for R&D in 2007, for a revised total of $856,000 for non-EPRI R&D projects in the test year (see HECO T-13, Attachment 2). The Company also agrees to provide the Consumer Advocate with copies of the co-funding agreement with EPRI and its co-matching check to support the biofuels crop study that the Hawaiian Agriculture Research Center would oversee. Furthermore, the Company agrees to spend at least the amount of EPRI dues ($1,608,000) plus the non-EPRI R&D amount ($856,000) on a recurring annual basis. Based on the above, the Consumer Advocate and DOD accept the Company's proposal.

Expiring Software Amortization

As discussed in subparagraph 7.f. above, the Parties' differences with respect to the inclusion of the MINCOM amortization has been settled. Based on the settlement, the Company agrees to remove the MINCOM amortization expenses allocated to Miscellaneous A&G expenses).

EEI Membership Dues

The Company estimated EEI dues of $198,000 in direct testimony, HECO T-13. This estimate excluded a portion of the EEI dues that related to government lobbying, based on information provided by EEI on its 2006 invoices. DOD proposed an additional exclusion of $61,000, calculated on a larger exclusion percentage. This larger percentage was based on the amounts EEI spent on legislative and regulatory advocacy, advertising, marketing, and public relations activities in 2005. The proposed exclusion percentage was adopted by the Arkansas Public Service Commission in Docket No. 06-101-U. The Company did not accept the DOD's proposal but, for settlement purposes, agrees to exclude an additional $37,000, based on the percentage of EEI's 2006 expenditures for legislative advocacy, legislative policy research, advertising, marketing, and public relations (see HECO T-13, Attachment 1). The DOD and Consumer Advocate accept the Company's proposal.

g. Pension Tracking Mechanism

As a result of the settlement reached between HELCO and the Consumer Advocate regarding the implementation of a pension tracking mechanism for HELCO in Docket No. 05-0315 (HELCO's 2006 test year rate case), HECO proposed a pension tracking mechanism in the instant proceeding. (See June 2007 Update HECO T-10 Attachment 8, filed on June 27, 2007.)

Although HECO and the Consumer Advocate agree to implementation of a pension tracking mechanism, the Consumer Advocate disagrees with HECO's proposal to include the amortization of the test year pension asset balance (resulting in an expense $5,055,000) in test year revenue requirements (Schedule C-18). The DOD objects to the implementation of a pension tracking mechanism. Further, the DOD also objects to HECO's proposed inclusion of amortization of test year ending pension asst of $5,055,000 in test year revenue requirements.

For purposes of settlement, the Parties agree to a pension tracking mechanism that does not include the amortization of the pension asset as part of the pension tracking mechanism in this proceeding. Not including the amortization has the effect of deferring the issue of whether the pension asset should be amortized for rate making purposes to HECO's next rate case. In addition, under the tracking mechanism, HECO would only be required to fund the minimum level required under the law, until the existing pension asset amount is reduced to zero, at which time the Company would fund NPPC as specified in the pension tracking mechanism for HELCO.[5] If the existing pension asset amount is not reduced to zero by the next rate case, the Parties would address the funding requirements for the pension tracking mechanism in the next rate case. Furthermore, the pension tracking mechanism will require the Company to create a regulatory asset or regulatory liability, as appropriate, for the difference between the amount of NPPC

[5] This provision is different from the tracking mechanism that was agreed to for the pending HELCO rate case due to different fact and circumstances. In the HELCO rate case, the Parties were in agreement as to the inclusion of the pension asset in rate base and the amortization of the pension asset balance at the end of the test year. In the current HECO rate case, the Parties disagree as to whether the pension asset should be included in the test year rate base, as well as whether said balance should be amortized for rate making purposes. The issue as to whether such amortization should be recognized in the test year revenue requirement has been deferred to HECO's next rate case.

included in rates and actual NPPC recorded by the Company. See HECO T-10, Attachment 2 for the agreed upon pension tracking mechanism.

h. OPEB Tracking Mechanism

In this proceeding, HECO proposed an OPEB tracking mechanism. (See June 2007 Update HECO T-10 Attachment 9, filed on June 27, 2007.) HELCO and the Consumer Advocate previously agreed to the implementation of an OPEB tracking mechanism for HELCO in Docket No. 05-0315 (HELCO's 2006 test year rate case).

The Consumer Advocate indicated that the OPEB tracker was a non-event in the HELCO rate case. The DOD objected to the implementation of an OPEB tracking mechanism.

For purposes of settlement, the Parties agree to HECO's proposed OPEB tracking mechanism. The implementation of the OPEB tracking mechanism does not impact the test year revenue requirements in this case.

i. Corporate Administration

HECO's estimate of A&G expenses was reduced by $36,000, to remove the corporate administration expenses associated with the reclassification of DSM Program expenses for the six Customer Service employees removed from base rates (to be recovered through the IRP Clause) as discussed in paragraph 11 and subparagraph 11.b. This reduction is agreed to by the Parties.

DEPRECIATION AND AMORTIZATION

13. The Company's test year estimate of depreciation expense submitted in direct testimony was $79,736,000. With the update of actual plant additions in 2006, including updates to the historical 5-year averages for retirements, cost of removal and salvage, test year depreciation expense was adjusted by $973,000 to $78,763,000. The updated test year accumulated depreciation end of year balance increased by $3,652,000 from $1,188,793,000 to $1,192,445,000 due to lower 2006 plant retirements of approximately $3,400,000 and updated averages with the inclusion of 2006 recorded data (see June 2007 Update, HECO T-13). The Consumer Advocate and DOD accept the Company's updated estimates.

TAXES OTHER THAN INCOME TAXES

14. Revenue Taxes

In the settlement process, HECO suggested that the Consumer Advocate's test year estimate of taxes other than income taxes might be understated due to revenue tax expenses not being included for the 2005 test year rate case interim rate increase revenues (CA-101, Schedule C-2), and for only a portion of the interim surcharge revenues for DG fuel and trucking and LFSO trucking. The Consumer Advocate confirmed this error and the Parties agree that a correction was needed to add revenue taxes for the entire $57.2 million of the interim rate increase and surcharge revenues, increasing the

Consumer Advocate's test year revenue tax expenses at current effective rates by $4,928,000.

15. Payroll Taxes
The Consumer Advocate and HECO have calculated a reduction to HECO's estimate of payroll taxes associated with the average test year employee labor expense reductions made for the T&D, Customer Service, and other departments that charge to A&G accounts. Based on the estimated total test year average employee count reduction of 22, payroll taxes are reduced by $46,000 (see HECO T-14, Attachment 1(F)). In addition, HECO's estimate of Payroll Taxes was reduced by $26,000, to reflect the reclassification of DSM Program expenses for the six Customer Service employees removed from base rates (to be recovered through the IRP Clause) as discussed in paragraph 11 and subparagraph 11.b. For settlement purposes, the Consumer Advocate and DOD accept these adjustments.

16. Interest Synchronization
The DOD proposed an adjustment for interest synchronization to determine the interest deduction for the calculation of test year income tax expense. HECO did not agree with this proposal and did not use interest synchronization to develop its revenue requirements for the test year. The Parties took the same positions in Docket No. 04-0113 (HECO 2005 test year rate case). The final decision and order in Docket No. 04-0113 will determine whether interest synchronization will be used for that proceeding. For purposes of settlement, the Parties agreed to not relitigate the issue in this docket, that HECO's method of computing interest expense for the purposes of determining income taxes for the 2007 test year will be used in calculating the interim rate increase (as it was in Interim Decision and Order No. 22050 in Docket No. 04-0113), and that the interest synchronization methodology issue will be determined by the final non-appealable decision in Docket No. 04-0113. As a result, the Parties agree to waive evidentiary hearings and proposed findings of fact and conclusions of law with respect to this issue.

RATE BASE

17. In direct testimony, HECO T-17, the Company estimated the test year average rate base at $1,214,313,000. Subsequently, this estimate was updated to $1,201,212,000 (June 2007 Update (T-17) and the response to DOD-IR-96), based on updated rate base component amounts such as the replacement of 2006 year-end estimates with recorded amounts, inclusion of the Asset Retirement Obligation regulatory asset, and changes to working cash. The Consumer Advocate and DOD accepted the Company's test year average rate base estimate except for three items: 1) inclusion of the pension asset and the related component of accumulated deferred income taxes ("ADIT") (Schedule B-2); 2) the estimate of cash working capital (Schedule B-3); and 3) an element of ADIT related to AFUDC in Construction Work in Progress ("CWIP") (Schedule B-5). In addition, the Consumer Advocate did not accept the Company's fuel inventory estimate, based on slight differences in the results of its production simulation model with respect to the LSFO burn rate (Schedule B-4). Based on these differences, the Consumer

Advocate's estimate of the test year average rate base was $1,156,048,000 (CA-101, Schedule B) and DOD's estimate was $1,150,720,000. As discussed below, for purposes of settlement, the Parties agree to the cash working capital, the ADIT component related to CWIP and fuel inventories. The Parties have not reached agreement on whether the Pension Asset should be included in rate base, but agree that related ADIT should be excluded from rate base if the Pension Asset is excluded from rate base, and that the Pension Asset will not be included in rate base for purposes of the interim increase (pending issuance of a final decision and order in Docket No. 04-0113).

18. <u>Fuel Inventories</u>
Test year fuel inventory was $52,706,000 in direct testimony and updated to $53,084,000 in HECO T-4 June 2007 Update. For purposes of settlement, the Consumer Advocate and the DOD accept HECO's average test year balance of $53,084,000 as shown in HECO T-17 June 2007 Update. HECO's test year estimate is based on the updated production simulation results provided in response to CA-IR-214 and HECO T-4 June 2007 Update.

19. <u>Materials and Supplies Inventory</u>
The Parties are in agreement with HECO's Production inventory of $6,678,000 and T&D inventory of $6,160,000 and the Company's $12,838,000 average Materials and Supplies inventory as shown in HECO-1703 in direct testimony.

20. <u>Pension Asset</u>
HECO proposed to include $59,405,000 of pension asset in the test year average rate base. The portion of the Accumulated Deferred Income Taxes (ADIT) related to the pension asset amounts to $23,114,000. The Parties agreed that the exclusion of all or a portion of the pension asset in rate base will also require corresponding adjustment to ADIT.

The Consumer Advocate and the DOD oppose the inclusion of HECO's pension asset in rate base in this proceeding. Whether a pension asset[6] should be included in rate base is an issue in HECO's 2005, test year rate case (Docket No. 04-0113). In Interim Decision and Order No. 22050, the Commission found that HECO was probably entitled to include its pension asset in rate base. The Commission noted, however, that its decisions and rulings in the Interim Decision and Order were subject to a more detailed review and analysis, including a review of the Parties' post-hearing briefs. As a result, the Commission will make a determination on that issue in the final decision and order in Docket No. 04-0113 based on the record in that proceeding.

The Parties are unable to reach agreement on this issue. The Parties agree to address the issue in their respective proposed findings of fact and conclusion of law and responses to proposed findings of fact and conclusions of law, based on the record in this proceeding.

[6] The pension amount in rate base was referred to as "prepaid pension asset" in Docket No. 04-0113; however, with the adoption of FAS 158, the amount is now referred to as "pension asset."

In addition, the Parties agree to incorporate by reference the record on this issue from Docket No. 04-0113. The Parties also agree that further examination of the issue at an evidentiary hearing is unnecessary, and the Parties waive their rights to a hearing on this issue.

For purposes of an interim decision in this proceeding, the Parties agree to exclude the pension asset and related ADIT from rate base.

21. <u>Accumulated Deferred Income Taxes</u>

In its direct testimony (HECO T-15), the Company proposed an average balance of $155,081,000 for accumulated deferred income taxes ("ADIT") in the 2007 test year. In its June 2007 Supplemental update for HECO T-15, the Company reduced its test year estimate of the ADIT average balance to $146,062,000. Both the Consumer Advocate and DOD proposed an adjustment of $8,157,000. This adjustment was intended to reverse an adjustment made by HECO in its June 2007 Update for HECO T-15 that eliminated from rate base the deferred taxes associated with AFUDC in CWIP.

For purposes of settlement, the Parties accepted the Company's proposed option to include in rate base the deferred taxes related to both the AFUDC in CWIP and tax capitalized interest "TCI", under the condition that the entire balance of the Regulatory Asset for AFUDC Equity Gross Up and the related deferred taxes also be included in rate base (thus eliminating HECO's proposed adjustment to this Regulatory Asset). This option results in a $5,524,227 reduction to rate base as shown in HECO T-15 Attachment 1. See also the Pension Asset section above that discusses the agreed upon exclusion of the ADIT related to pension asset of $23,114,000 from rate base if the pension asset is excluded from rate base.

22. <u>Working Cash</u>

The Parties agreed on the items included in the working cash calculation and the revenue and payment lag days except as described below:

a. Pension Asset Amortization – The Company had proposed the inclusion of pension asset amortization in the working cash calculation; however, as a result of the removal of pension asset amortization from revenue requirements in this rate case as discussed above, there is no issue with respect to the working cash relating to the pension asset amortization.

b. Pension Expense – The Company's original position was that with the pension asset included in rate base (and prior to the consideration of a pension tracking mechanism), the pension expense should be included in the working cash calculation with a revenue collection lag of 37 days and a payment lag of zero days based on the inclusion of the pension asset in rate base. The Company's position on payment lag days was increased to 14 days based on implementing the pension tracking mechanism which required NPPC funding (with certain exceptions) and the expectation that pension funding under the pension tracking mechanism would be at the end of each month. The Consumer Advocate objected to the inclusion of pension expense in the working cash calculation absent plans or a study specifically analyzing pension cash flows. Acknowledging that the Company does not have specific data on which to base its pension payment lag study, the Company subsequently proposed to increase the payment lag for pension expense from 14 days to 30 days (the payment lag days for "other" O&M non-labor items). The DOD proposed that the pension expense be included in the working cash with 182.5 payment days based on an assumption that HECO would not be contributing to the pension fund in the test year and with no pension asset in rate base. For purposes of settlement and with the acknowledgement that settlement on this item does not reflect any party's position on the inclusion of pension asset in rate base, the Parties agree to excluding pension expense from the working cash calculation.

c. Amortization Expenses – The Company's position was that these items were paid for in advance of the expense recognition and have zero or negative payment lags or should be included as rate base items. However, the Company proposed to apply the "other" non-labor O&M payment lag day to these items, in recognition of the fact that the Company has not done an extensive search for all amortization items. The Consumer Advocate and the DOD proposed that amortization expenses (system development costs, regulatory commission expense, Waiau water well, Kahe Unit 7) should be removed from the working cash calculation on the basis that these are non-cash transactions. For purposes of settlement, the Parties agree to the inclusion of other amortization items in the working cash calculation with a 30 day payment lag.

The revised O&M non-labor payment lag days estimate, as a result of incorporating the above discussed items, is 34 days. Other differences in the working cash resulted from differences in the related expense items. For purposes of settlement, the Parties agree to the O&M non-labor payment lag days of 34 (see HECO T-17, Attachment 1) and to the exclusion of pension expense from O&M non-labor in the calculation of working cash.

COST OF CAPITAL

23. Capitalization

HECO proposed the following capitalization amounts and weights:

	HECO T-19, Attachment 5 & HECO-1901 Direct Testimony Amounts ($000)	Weights (%)
Short-term borrowing	38,971	3.08
Long-term borrowing	480,727	38.01

Hybrid securities	27,556	2.18
Preferred stock	20,586	1.63
Common stock	696,825	55.10

The Consumer Advocate agreed to utilize the capital structure proposed by HECO.

The DOD proposed a test year capital structure based on the average actual quarter-end capitalization for 5 quarters beginning with quarter-end March 2006 and ending with quarter-end March 2007.

For purposes of settlement, the Parties agree to the capital structure proposed by HECO.

24. Cost of Capital. There were no differences between HECO, the Consumer Advocate and the DOD with respect to the cost rates for short-term debt, long-term debt, hybrid securities and preferred stock. The weighted earnings requirement for short-term debt, long-term debt, hybrid securities and preferred stock is the same for HECO and the Consumer Advocate. The DOD's weighted earnings requirement for short-term debt, long-term debt, hybrid securities and preferred stock differed due to the DOD's proposed capitalization. For purposes of settlement, the Parties agree to the capital structure as discussed above, therefore there are no differences related to the weighted earnings requirements for short-term debt, long-term debt, hybrid securities and preferred stock.

25. Return on Common Equity and Composite Cost of Capital
In HECO's 2007 test year rate case direct testimony, HECO recommended a rate of return on common equity of 11.25% in direct testimony.[7] This resulted in an overall cost of capital of 8.92%. The Consumer Advocate proposed that the cost of common equity for HECO is within a broad range of 9.00% to 11.00%, but proposed to use the middle portion of this range and thus recommended a range of 9.50% to 10.50% for the rate of return on common equity. This resulted in an overall cost of capital in the range of 7.96% to 8.51% (8.23% mid-point which incorporates a cost of common equity of 10.00%). The Consumer Advocate's specific cost of capital recommendation for HECO was 8.23%. (CA-T-4 at 4, l.24 to 5, l.6.) The DOD estimated a range for the rate of return on common equity (9.00% to 9.75%), with a mid-point of 9.375% and a specific cost of equity recommendation of 9.25%. The 9.25% applied to the DOD's proposed capitalization for HECO produced a cost of capital of 7.70%.

For the purpose of reaching a global settlement in this rate case, HECO, the Consumer Advocate and the DOD agree on a rate of return on common equity of 10.7% for the test year. This results in a composite cost of capital of 8.62%. See HECO T-19, Attachment 5.

[7] In the settlement negotiations, the Company also provided supplemental information regarding its credit ratings. See August 2007 Supplement for T-19 for the supplemental information.

COST OF SERVICE/RATE INCREASE ALLOCATION/RATE DESIGN

Below are the agreements that HECO, the Consumer Advocate and the DOD have reached on cost of service/rate design issues.

26. Cost of Service Study

HECO provided its embedded cost of service study in direct testimony based on a cost classification methodology previously approved by the Commission. The Consumer Advocate proposed to change the classification of certain distribution costs from customer-related to demand-related costs, and proposed to change the classification of some non-fuel production O&M expenses from a demand to an energy classification. However, the Consumer Advocate indicated that it would not be unreasonable for the Commission to also consider the HECO approach using methods previously accepted by the Commission. The DOD witness reviewed the principal separations of costs between fixed and variable and reviewed the fixed costs between demand-related and customer-related costs and concluded that the HECO cost of service study uses reasonable methods.

For settlement purposes in this case:

1) The Parties concur that agreement on a cost of service methodology is not a requirement to settle the case. The agreements on revenue allocation and rate design presented below are reasonable given the results of both HECO's and the Consumer Advocate's proposed cost of service methodologies;

2) HECO agrees in its next rate case to present a cost of service study utilizing the same distribution classification methodology as it used in this case, as well as a cost of service scenario that classifies all distribution network costs (poles, conduits, lines, and transformers investment and expenses) as demand-related. HECO can present other cost of service scenarios, if desired, and make whatever recommendations it chooses regarding interpretation and utilization of cost of service evidence; and

3) HECO agrees to conduct studies designed to isolate the demand (fixed) versus energy (variable) elements of its non-fuel production O&M expenses for use in the next HECO rate case, to be included in all of HECO's cost of service scenarios.

27. Inter-Class Allocation of Rate Increase

HECO proposed to assign the same percentage revenue increase to each rate schedule. The Consumer Advocate also proposed that the rate increase should be implemented as an equal percentage increase among rate classes, given its proposed size of revenue increase and in consideration of customer impacts as well as the cost of service study results. The DOD recommended that any approved rate increase be allocated among customer classes, viewing Schedule PS, Schedule PP, and Schedule PT as a single Schedule P class, with the objective of reducing the existing interclass subsidies.

For settlement purposes, the Parties agree to allocate any interim or final increase in electric revenues to rate classes in the percentages shown in HECO T-20, Attachment 1. This settlement considers the positions of HECO, the Consumer Advocate, and the DOD on cost of service and movement of inter-class revenues towards the respective cost of service positions.

The Parties further agree that Schedule P electric revenues established by this allocation will be further adjusted in the following amounts for the Schedule PP billing credit described in the Rate Design section below: Schedule PP revenues will be decreased by approximately $2.5 million, Schedule PS revenues will be increased by approximately $2.2 million, and Schedule PT revenues will be increased by approximately $0.3 million, as shown in HECO T-20, Attachment 1.

The Parties agree that the effect of the stipulated revenue increase allocations, Schedule PP billing credit, and Schedule PS, Schedule PP, and Schedule PT revenue adjustments will be reflected in the approved interim rate increase as follows: Since the interim rate increase will be implemented as a percentage applied to base revenue charges, similar to the implementation of the interim rate increase approved in HECO's test year 2005 rate case, HECO will make the appropriate billing system adjustments to apply a different percentage interim rate increase to Schedule PP customers that are directly served by a dedicated substation and to those that are not, in order to implement the effect of a $3.25 per kW credit and the stipulated revenue adjustments to Schedule PS, Schedule PP, and Schedule PT.

28. Intra-Class Rate Design

The Company's rate design proposal included customer charges based on the settlement agreement in the test year 2005 rate case, a Schedule R inclining block rate design, and increases to proposed commercial demand and energy charges based on the HECO cost of service study and the HECO proposed revenue requirement. The Consumer Advocate proposed that HECO retain the existing residential single phase minimum charge while agreeing with the Company's proposed customer charges.

The Consumer Advocate recognized that HECO's demand charges represent only a fraction of full unit demand cost, but recommended that demand charges be adjusted upwards more gradually than the Company proposal so as to mitigate rate impacts on low load factor customers. The Consumer Advocate recommended that demand charges increase no more than 10% above those agreed upon in the test year 2005 settlement, with any remaining revenue requirement recovered through energy charges. The DOD generally supported the rate design in Schedules PS, PP, and PT, but suggested that HECO's proposed discount for Schedule PP customers directly served from distribution substations should be $3.38 per kW rather than the $1.75 per kW proposed by HECO.

For settlement purposes, the Parties agree to the following concepts for overall rate design:

1) Customer charges will be set at the level proposed in settlement in the HECO 2005 test year case (see HECO's settlement transmittal letters of September 16, 2005 and September 22, 2005 in Docket No 04-0113);

2) Demand charges for Schedule J and Schedule H will be increased no more than 15% above the levels proposed in settlement in the HECO 2005 test year case. Demand charges for Schedule PS, Schedule PP, and Schedule PT will be increased no more than 25% above the levels proposed in settlement in the HECO 2005 test year case (see HECO's settlement transmittal letters of September 16, 2005 and September 22, 2005 in Docket No 04-0113);

3) Schedule PP will include a billing credit of $3.25 per billing kW for customers who are directly served from a dedicated substation. The amount of the credit is an agreed upon value to approximate the reduced level of costs that these customers impose on the HECO system. The Company's position is that neither the HECO cost of service study nor the cost of service study approach proposed by the Consumer Advocate accurately depicts the cost to serve Schedule PP customers who are directly served from a dedicated substation. As part of this settlement, the Company agrees in the next HECO rate case to include in the cost of service and propose in rate design a separate rate class for customers who are directly served from a dedicated substation. In this case, the Parties further agree that, to manage the billing impact on Schedule PP customers, the amount of the billing credit above $1.75 per billing kW ($1.50 per billing kW or approximately $2.5 million) will be recovered ratably based on billing kW from Schedule PS and Schedule PT customers;

4) Consideration of the power factor adjustment provision will be deferred to HECO's next rate case. HECO will provide updated estimates regarding completion of its power factor cost study and a plan to recommend appropriate cost-based power factor revisions in the rate design;

5) After revenues are assigned for proposed customer and demand charge levels, the recovery of the remaining class revenue requirement will be from energy charges;

6) HECO indicated in the press release that accompanied its filing of the application in this case that it would develop a proposal to assist low-income customers. The Parties agree for settlement purposes that the Company's proposed Schedule R should be modified to include a provision for customers in the LIHEAP program to be waived from the higher two tiers of the non-fuel energy charges, which is similar to the proposal before the Commission in the HELCO test year 2006 rate case. The impact of the LIHEAP waiver on

revenues is expected to be relatively small and is not included in the calculation of revenues at proposed rate. Therefore, the LIHEAP waiver will have no impact in this rate case on the amount of the rate increase for other customers; and

7) For Schedule R, the percentage increase for customers with usages that fall into the lowest non-fuel energy kWh tier will be lower than the overall percentage revenue increase assigned to the Schedule R class. This rate design impact will not take effect until the non-fuel energy rate tiers are approved with a final decision and order in this case.

The settlement rate designs, including the optional time-of-use rates (Schedule TOU-R, Schedule TOU-C, and Schedule U), are attached in HECO T-20, Attachment 2.

29. <u>Other Revisions to Rate Schedules and Rules</u>

The Parties agree for settlement purposes to the following other revisions to rate schedules:

1) The clarification of the Apartment House Collection Arrangement in Schedule R;
2) No changes to Schedule E;
3) Modification of Schedule J to add a maximum qualifying load of less than 300 kW for new customers and to add a clause that allows existing customers with loads equal or greater than 300 kW to remain on Schedule J;
4) Modification of the Schedule J billing demand ratchet from the current 75% ratchet to the average demand ratchet (same as Schedule P);
5) Modification of Schedule J, Schedule PS, Schedule PP, and Schedule PT to include a five year term of contract provision and add a service termination charge, which is the same proposal advanced by the Company in the test year 2005 rate case;
6) Closing Schedule H to new customers. HECO will eliminate Schedule H in its rate design proposal in the next HECO rate case;
7) Modification of Schedule PS, Schedule PP, and Schedule PT to add a minimum qualifying load of 300 kW for new customers and to add a clause that allows existing customers with loads less than 300 kW to remain on Schedule PS, Schedule PP, and Schedule PT;
8) Elimination of the 150 kW minimum power service under the Schedule PS, Schedule PP, and Schedule PT minimum billing provision;
9) For Rider T, adding terms and conditions to allow customers to do emergency maintenance on their generating equipment without considering its impact on the customers' maximum on-peak demand in the determination of their billing demand;
10) For Rider M, changing the initial term of contract to five years;
11) Closing Rider I to new customers;

12) For Schedule Q, implementing the changes proposed by HECO;
13) Changing the Returned Checks Charge, Field Collection Charge, and Service Establishment Charge as described in the section on Other Revenues;
14) Eliminating the Rule No. 4, Section D, Standard Form Customer Retention Rates; and
15) Eliminating the electric vehicle charging rates, Rider EV-R and Rider EV-C.

Hawaiian Electric Company, Inc.
2007 Rate Case
Purchase Power Expense

HECO T-5
ATTACHMENT 1
PAGE 1 OF 1
FINAL SETTLEMENT

	June 2007 Update	August Fix to AES Avg MW	Difference Between August Fix and June 2007 Update
Kalaeloa			
GWH	1,490.246	1,490.246	0.000
Energy			
Fuel	$ 147,835,016	$ 147,835,016	$ -
Non-fuel	$ 20,813,911	$ 20,813,911	$ -
Capacity	$ 32,719,000	$ 32,719,000	$ -
AES			
GWH	1,539.910	1,539.910	0.000
Energy			
Fuel	$ 41,417,513	$ 42,037,179	$ 619,666
Variable O & M	$ 1,242,711	$ 1,242,711	$ -
Fixed O & M	$ 27,335,015	$ 27,335,015	$ -
Capacity	$ 67,890,779	$ 67,890,779	$ -
Bonus	$ 1,154,174	$ 1,154,174	$ -
H-POWER			
GWH	337.436	337.436	0.000
Energy	$ 38,811,889	$ 38,811,889	$ -
Capacity	$ 6,876,821	$ 6,876,821	$ -
Chevron			
GWH	0.589	0.589	0.00
Energy cost	$ 77,482	$ 77,482	$ -
Tesoro			
GWH	5.304	5.304	0.000
Energy cost	$ 697,850	$ 697,850	$ -
Total Energy cost	$ 278,231,387	$ 278,851,053	$ 619,666

8/13/2007

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AES Hawaii, Inc. 2007 Operational/Budget Forecasted Expenses
5/21/2007 Production Simulation Update - Rate Case

Assumptions:

Forced Outage Rate	1.00%	3rd Q 2006 GNPIPD	116.414
Base GNPIPD	72.465	1st Q 2007 GNPIPD	117.510
Capacity-$/kWh available	$0.044095	Fixed O&M-$/kWh available	$0.011
Variable O&M-$/kWh purchased	$0 0005		

	ONE BOILER			TWO BOILERS			EAF CALCULATION		TOTAL FACILITY					
	net MWh	Op Hrs	Avg MW	net MWh	Op Hrs	Avg MW	Monthly EAF	YTD EAF	Energy MWh	Fuel	Variable O&M	Fixed O&M	Capacity	Total Expense
Jan	0	0	0.000	132,883	738	180.009	99.00%	99.00%	132,883	$3,607,725	$106,737	$2,342,881	$5,846,150	$11,903,493
Feb	0	0	0.000	119,578	664	180.006	99.00%	99.00%	119,578	$3,246,496	$96,050	$2,116,151	$5,280,394	$10,739,091
Mar	0	0	0.000	132,495	736	179.996	99.00%	99.00%	132,495	$3,597,178	$106,426	$2,342,881	$5,846,150	$11,892,635
Apr	0	0	0.000	128,563	714	180.010	99.00%	99.00%	128,563	$3,490,439	$103,267	$2,267,304	$5,657,565	$11,518,575
May	0	0	0.000	132,408	736	180.000	99.00%	99.00%	132,408	$3,594,820	$106,356	$2,342,881	$5,846,150	$11,890,207
Jun	0	0	0.000	128,477	714	179.990	99.00%	99.00%	128,477	$3,488,086	$103,198	$2,267,304	$5,657,565	$11,516,153
Jul	0	0	0.000	132,365	735	179.990	99.00%	99.00%	132,365	$3,627,477	$107,322	$2,364,938	$5,846,150	$11,945,888
Aug	0	0	0.000	132,495	736	179.996	99.00%	99.00%	132,495	$3,631,044	$107,428	$2,364,938	$5,846,150	$11,949,561
Sep	0	0	0.000	128,909	716	179.990	99.00%	99.00%	128,909	$3,532,764	$104,520	$2,288,650	$5,657,565	$11,583,499
Oct	21,384	238	90.000	89,381	497	179.986	83.03%	97.37%	110,765	$3,069,158	$89,809	$1,983,497	$4,903,223	$10,045,687
Nov	0	0	0.000	128,434	714	180.006	99.00%	97.52%	128,434	$3,519,761	$104,135	$2,288,650	$5,657,565	$11,570,111
Dec	0	0	0.000	132,538	736	180.005	99.00%	97.64%	132,538	$3,632,232	$107,463	$2,364,938	$5,846,150	$11,950,783
Total	21,384	238	90.000	1,518,526	8,436	179.999		97.64%	1,539,910	$42,037,179	$1,242,711	$27,335,015	$67,890,779	$138,505,683

Bonus: $1,154,174

Total Expense: $139,659,857

DATA SOURCES AND NOTES:

Refer to the letter grid across the top of the page for the column address and the line number on the left side for the row number. General reference to a column without reference to a row means to use the data for the corresponding month. Otherwise a specific row reference is in ( ) next to the column designation. Calculation on one sheet of the spreadsheet may draw on data from another sheet. Elements of a formula that reference data from another sheet are preceded by an "A:" if the data are from the SUMMARY sheet and preceded by a "B:" if the data are from the BACKUP sheet.

1. Forced Outage Rate in cell F(9) is based on approximate actual performance.
2. Base GNPIPD in cell F(10) is the GNPIPD value for the 1st Quarter of 1987 per the AES-Hawaii PPA, Amendment 1, Exhibit 5, p14. Actual value will be from the same Bureau of Economic Analysis publication as the actual current GNPIPD (numerator in GNPIPD adjustment factor), per the May 3, 2001 letter agreement. For now, a recent 1Q1987 GNPIPD value is used for the Base GNPIPD.
3. Capacity cost per available kWh in cell F(11) is based on AES Hawaii PPA, Amendmen dated May 8, 2003, p. 2.
4. Variable O&M cost per kWh purchased in cell F(12) is based on AES-Hawaii PPA, Amendment 1, p7.
5. 3rd Q 2006 GNPIPD in cell K(9) is the actual final value.
6. 1st Q 2007 GNPIPD in cell K(10) is based on the GDP Chain-Type Price Index escalation per Energy Information Administration / Annual Energy Outlook 2007 (Tab (Macroeconomic Indicators), page 165, published February 2007) from the Internet (http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2007).pdf; visited site on 5/23/2007).
7. Fixed O&M cost per available kWh in cell K(11) is based on AES-Hawaii PPA, Amendment 1, p7.
8. The net MWh and Op Hrs in columns C and D, respectively and columns F and G, respectively are from the HECO 2007 Operational/Budget Production Simulation dtd 5/21/2007.
9. The Avg MW in col E is calculated from C / D. The Avg MW in col H is calculated from F / G.
10. The Monthly EAF in col I is calculated from ((B:C * 24) - B:D - B:E) / (B:C * 24).
11. The YTD EAF in col J is calculated as follows. The first month is from I. Subsequent months are calculated from J (from previous month) * (sum B:C(existing and previous months) * 24) + (I * B:C * 24) / (sum B:C(existing and previous months) * 24).
12. The Energy MWh in col K is calculated from C + F.
13. The Fuel cost in col L is calculated from ((B:J * B:G * F) + (B:H * B.G * C)) * 1000 / 100.
14. The Variable O&M cost in col M is calculated from F(12) * 1000 * B:G * K.
15. The Fixed O&M cost in col N is calculated from K(11) * 1000 * B:F * B:G.
16. The Capacity cost in col O is calculated from F(11) * 1000 * B:F.
17. The Total Expense in col P is calculated by L + M + N + O.
18. The Bonus is calculated on the "Bonus" and "Detailed Bonus Calc" sheets.

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AES Hawaii, Inc. 2007 Operational/Budget Forecasted Expenses
5/21/2007 Production Simulation Update - Rate Case

Assumptions: See SUMMARY sheet

	AVAILABILITY DATA					ONE BOILER		TWO BOILERS	
	Calendar Days	Planned Maintenance EHrs Out	Forced Outage EHrs Out	MWh Available	GNPIPD Ratio	Base Fuel Component cents/kWh	Fuel	Base Fuel Component cents/kWh	Fuel
Jan	31	0	7.44	132,581	1.606486	0.000000	$0	1.690001	$3,607,725
Feb	28	0	6.72	119,750	1.606486	0.000000	$0	1.69	$3,246,496
Mar	31	0	7.44	132,581	1.606486	0.000000	$0	1.689995	$3,597,178
Apr	30	0	7.20	128,304	1.606486	0.000000	$0	1.690001	$3,490,439
May	31	0	7.44	132,581	1.606486	0.000000	$0	1.689997	$3,594,820
Jun	30	0	7.20	128,304	1.606486	0.000000	$0	1.689993	$3,488,086
Jul	31	0	7.44	132,581	1.621610	0.000000	$0	1.689993	$3,627,477
Aug	31	0	7.44	132,581	1.621610	0.000000	$0	1.689995	$3,631,044
Sep	30	0	7.20	128,304	1.621610	0.000000	$0	1.689993	$3,532,764
Oct	31	120	6.24	111,197	1.621610	1.786989	$619,666	1.689991	$2,449,493
Nov	30	0	7.20	128,304	1.621610	0.000000	$0	1.69	$3,519,761
Dec	31	0	7.44	132,581	1.621610	0.000000	$0	1.69	$3,632,232
Total	365	120	86.4	1,539,648			$619,666		$41,417,513

DATA SOURCES AND NOTES: See SUMMARY sheet and below

Refer to the letter grid across the top of the page for the column address and the line number on the left side for the row number. General reference to a column without reference to a row means to use the data for the corresponding month. Otherwise a specific row reference is in ( ) next to the column designation. Calculation on one sheet of the spreadsheet may draw on data from another sheet. Elements of a formula that reference data from another sheet are preceded by an "A:" if the data are from the SUMMARY sheet and preceded by a "B:" if the data are from the BACKUP sheet.

19. Planned Maintenance Equivalent Hours (EHrs) Out in col D assumes 10 days of 90 MW out normalized maintenance (in October).

20. The Forced Outage Equivalent Hours (EHrs) Out in col E is calculated from A:F(9) * ((C * 24) - D).
21. The MWh Available in col F is calculated from 180 * ((C * 24) - D - E).
22. The GNPIPD ratio in col G is calculated from A:K(9) / A:F(10) for the months January through June and from A:K(10) / A:F(10) for the months of July through December.
23. The Base Fuel Component in cents per kWh in col H is calculated from the formula in the AES-Hawaii PPA, Amendment 1, p7. The load data are from A:E.
24. The Fuel cost in col I is calculated from A:C * H * (1000 / 100) * G.
25. The Base Fuel Component in cents per kWh in col J is calculated from the formula in the AES-Hawaii PPA, Amendment 1, p7. The load data are from A:H.
26. The Fuel cost in col K is calculated from A:F * J * (1000 / 100) * G.

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AES Hawaii, Inc. 2007 Operational/Budget Forecasted Expenses
5/21/2007 Production Simulation Update - Rate Case
AES Availability Bonus

Two Year Running Avg.
Equivalent Availability Factor (EAF): 96.94%

Per PPA Section 5.2: Availability bonus = $15,000 (1987$) per one tenth of a percentage point over 91%, adjusted in accordance with Section 8.1C

Per PPA Section 8.1C: *All dollar values noted in Sections 5.2 and 8.1 will be* adjusted each Contract Year in accordance with the following formula:

Bonus Corrected = ((C + U) / (C + E)) X GNPIPD Ratio X Liquidated Damage or Bonus (Uncorrected)

C = Capacity Charge
E = Escalated Energy Charge
U = Unescalated Energy Charge

GNPIPD current (forecasted 1st Q for year of payment)	117.510	
GNPIPD base	72.465	
GNPIPD Adjustment Factor	1.6216	
C	4.4095	cents/kWh
U (Fuel equation with 180 MW * EAF as input for plant load + Variable O&M component (0.05 cents/kWh) + Fixed O&M component (1.1 cents/kWh))	2.84	cents/kWh
E (U * (GNPIPD current/GNPIPD base)	4.6023	cents/kWh
((C+U)/(C+E))	0.804237244	
EAF > 91% (truncated to nearest 0.1%)	5.9%	
Bonus uncorrected	$885,000	
Bonus Corrected	**$1,154,174**	

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AES HAWAII, INC. BONUS EQUIVALENT AVAILABILITY CALCULATION

Assumption of forced outage rate for Contract Year 14 1.0 percent

Month	Potential kWh	Available kWh	Monthly Percentage	Contract Year Cumulative Percentage
Contract Year 14				
Oct-05	133,920,000	133,920,000	100.00%	100.00%
Nov-05	129,600,000	129,600,000	100.00%	100.00%
Dec-05	133,920,000	133,918,449	100.00%	100.00%
Jan-06	133,920,000	94,848,511	70.82%	92.65%
Feb-06	120,960,000	98,541,482	81.47%	90.57%
Mar-06	133,920,000	132,223,208	98.73%	91.96%
Apr-06	129,600,000	128,032,137	98.79%	92.93%
May-06	133,920,000	124,015,619	92.60%	92.89%
Jun-06	129,600,000	129,452,093	99.89%	93.66%
Jul-06	133,920,000	133,920,000	100.00%	94.30%
Aug-06	133,920,000	133,919,871	100.00%	94.83%
Sep-06	129,600,000	129,599,652	100.00%	95.26%
Totals	1,576,800,000	1,501,991,022		**95.26%**

Notes

1. Actual data used through September 2006.

TWO YEAR RUNNING AVERAGE EAF FOR CONTRACT YEARS 13 AND 14	**97.21%**
PPA EAF BONUS THRESHOLD	91.0%
PPA BONUS EAF FACTOR (Truncated to 0.1%)	6.2%
PPA BONUS IN UNCORRECTED DOLLARS ($1987)	$930,000.00
PPA BONUS CORRECTED FORMULA	

Capacity = C	C in cents/kWh =	4.4095
Uncorrected Energy = U	U in cents / kWh = ((fuel equation with 180 MW*EAF as input) + 1.10 + 0.05)	2.84
Corrected Energy = E	E = U * GNPIPD Adjustment Factor =	4.48
	GNPIPD Current value assumed (on payment date)=	**114.352**
GNPIPD adjustment factor =	Current value / 1987 1st Qtr value (72.465) =	1.5780
(C + U) / (C + E) =		0.815430145

PPA BONUS PAYMENT CORRECTED	((C +U)/(C +E)) * GNPIPD adjustment factor * Uncorrected Bonus	$1,196,676.36
EAF BONUS	*CONTRACT YEARS 13 AND 14* Payable November, 2006	**$1,196,676.36**

Assumption of forced outage rate for Contract Year 15 1.0 percent

Month	Potential kWh	Available kWh	Monthly Percentage	Contract Year Cumulative Percentage
Contract Year 15				
Oct-06	133,920,000	128,955,565	96.29%	96.29%
Nov-06	129,600,000	129,164,620	99.66%	97.95%
Dec-06	133,920,000	129,548,913	96.74%	97.54%
Jan-07	133,920,000	132,580,800	99.00%	97.91%
Feb-07	120,960,000	119,750,400	99.00%	98.11%
Mar-07	133,920,000	132,580,800	99.00%	98.26%
Apr-07	129,600,000	128,304,000	99.00%	98.37%
May-07	133,920,000	132,580,800	99.00%	98.45%
Jun-07	129,600,000	128,304,000	99.00%	98.51%
Jul-07	133,920,000	132,580,800	99.00%	98.56%
Aug-07	133,920,000	132,580,800	99.00%	98.60%
Sep-07	129,600,000	128,304,000	99.00%	98.63%
Totals	1,576,800,000	1,555,235,498		**98.63%**

Notes

1. Actual data used through December 2006.

TWO YEAR RUNNING AVERAGE EAF FOR CONTRACT YEARS 14 AND 15	**96.94%**
PPA EAF BONUS THRESHOLD	91.0%
PPA BONUS EAF FACTOR (Truncated to 0.1%)	5.9%
PPA BONUS IN UNCORRECTED DOLLARS ($1987)	$885,000.00
PPA BONUS CORRECTED FORMULA	

Capacity = C	C in cents/kWh =	4.4095
Uncorrected Energy = U	U in cents / kWh = ((fuel equation with 180 MW*EAF as input) + 1.10 + 0.05)	2.84
Corrected Energy = E	E = U * GNPIPD Adjustment Factor =	4.60
	GNPIPD Current value assumed (on payment date)=	**117.510**
GNPIPD adjustment factor =	Current value / 1987 1st Qtr value (72.465) =	1.6216
(C + U) / (C + E) =		0.804237244

PPA BONUS PAYMENT CORRECTED	((C +U)/(C +E)) * GNPIPD adjustment factor * Uncorrected Bonus	$1,154,173.74
EAF BONUS	*CONTRACT YEARS 14 AND 15* Payable November, 2007	**$1,154,173.74**

NET WRITE-OFFS		SALES REVENUES		
Mo/Yr	12 Months Ending	Mo/Yr	12 Months Ending	% Write-off *
Jul-02	931,019	Mar-02	859,986.8	0.10826%
Aug-02	912,549	Apr-02	855,493.9	0.10667%
Sep-02	793,242	May-02	851,635.4	0.09314%
Oct-02	773,313	Jun-02	852,288.1	0.09073%
Nov-02	766,756	Jul-02	851,115.2	0.09009%
Dec-02	764,393	Aug-02	848,860.0	0.09005%
Jan-03	792,559	Sep-02	844,623.1	0.09384%
Feb-03	792,473	Oct-02	845,847.8	0.09369%
Mar-03	831,944	Nov-02	850,081.3	0.09787%
Apr-03	840,975	Dec-02	858,635.7	0.09794%
May-03	683,004	Jan-03	869,367.4	0.07856%
Jun-03	795,584	Feb-03	882,400.9	0.09016%
Jul-03	970,816	Mar-03	899,062.1	0.10798%
Aug-03	952,196	Apr-03	911,131.8	0.10451%
Sep-03	937,554	May-03	923,370.9	0.10154%
Oct-03	958,486	Jun-03	933,521.6	0.10267%
Nov-03	951,452	Jul-03	938,160.0	0.10142%
Dec-03	975,434	Aug-03	945,952.4	0.10312%
Jan-04	955,302	Sep-03	953,462.8	0.10019%
Feb-04	962,704	Oct-03	956,538.5	0.10064%
Mar-04	974,837	Nov-03	959,694.7	0.10158%
Apr-04	965,425	Dec-03	960,784.2	0.10048%
May-04	811,993	Jan-04	963,593.2	0.08427%
Jun-04	707,004	Feb-04	968,410.5	0.07301%
Jul-04	588,208	Mar-04	969,442.2	0.06067%
Aug-04	546,681	Apr-04	971,772.5	0.05626%
Sep-04	562,260	May-04	973,013.3	0.05779%
Oct-04	492,445	Jun-04	974,892.1	0.05051%
Nov-04	567,413	Jul-04	981,537.5	0.05781%
Dec-04	534,055	Aug-04	987,643.7	0.05407%
Jan-05	502,903	Sep-04	996,558.0	0.05046%
Feb-05	489,908	Oct-04	1,009,179.8	0.04855%
Mar-05	467,996	Nov-04	1,022,596.2	0.04577%
Apr-05	440,622	Dec-04	1,036,013.4	0.04253%
May-05	510,033	Jan-05	1,049,133.2	0.04861%
Jun-05	422,289	Feb-05	1,052,081.4	0.04014%
Jul-05	429,831	Mar-05	1,053,587.6	0.04080%

NET WRITE-OFFS		SALES REVENUES		
Mo/Yr	12 Months Ending	Mo/Yr	12 Months Ending	% Write-off *
Aug-05	474,635	Apr-05	1,056,634.2	0.04492%
Sep-05	441,975	May-05	1,066,815.3	0.04143%
Oct-05	461,227	Jun-05	1,082,022.6	0.04263%
Nov-05	396,040	Jul-05	1,094,459.7	0.03619%
Dec-05	363,838	Aug-05	1,115,076.4	0.03263%
Jan-06	476,683	Sep-05	1,132,603.5	0.04209%
Feb-06	526,614	Oct-05	1,152,725.6	0.04568%
Mar-06	537,946	Nov-05	1,175,402.6	0.04577%
Apr-06	607,739	Dec-05	1,194,052.4	0.05090%
May-06	670,901	Jan-06	1,212,561.8	0.05533%
Jun-06	774,884	Feb-06	1,237,755.6	0.06260%
Jul-06	805,193	Mar-06	1,262,525.3	0.06378%
Aug-06	764,398	Apr-06	1,285,917.3	0.05944%
Sep-06	834,697	May-06	1,304,153.2	0.06400%
Oct-06	917,004	Jun-06	1,321,190.5	0.06941%
Nov-06	978,511	Jul-06	1,343,448.9	0.07284%
Dec-06	999,378	Aug-06	1,356,117.0	0.07369%
Jan-07	981,265	Sep-06	1,368,261.4	0.07172%
Feb-07	936,020	Oct-06	1,375,487.1	0.06805%
Mar-07	1,368,528	Nov-06	1,368,611.9	0.10000%
Apr-07	1,311,603	Dec-06	1,360,004.9	0.09600%
May-07	1,250,936	Jan-07	1,353,765.5	0.09200%
Jun-07	1,214,436	Feb-07	1,343,828.3	0.09000%

Jul '02 - Jun '07	45,450,107		63,224,890.2	0.0719%

Hawaiian Electric Company, Inc.
Comparison of
Energy Cost Adjustment Factors
Settlement, June 2007 Update and Direct Testimony

2007 Test Year - Settlement

(¢/kwh)

Present Rates				
Settlement (A)	June 2007 Update (B)	Direct Testimony (C)	Difference (A) - (B)	Difference (B) - (C)
7.340	7.331	7.299	0.009	0.032

Proposed Rates		
Settlement	June 2007 Update	Direct Testimony
0.000	0.000	0.000

HAWAIIAN ELECTRIC COMPANY, INC.
Comparison of
Composite Cost of Generation - Central Station
Settlement, June 2007 Update and Direct Testimony

2007 Test Year - Settlement
At Present Rates

Line		(A) Settlement and June 2007 Update at Present Rates	(B) Direct Testimony at Present Rates	(C) Difference (A) - (B)
	CENTRAL STATION			
	FUEL PRICES, ¢/mmbtu			
1	Kahe	1,055.65	1,050.17	5.48
2	Waiau	1,055.65	1,050.17	5.48
3	Honolulu	1,055.65	1,050.17	5.48
4	Diesel	1,707.34	1,698.53	8.81
5	DG	0.00	0.00	0.00
	BTU MIX, %			
6	Kahe	70.01	69.65	0.36
7	Waiau	25.14	25.10	0.04
8	Honolulu	3.56	3.62	-0.06
9	Diesel	0.85	1.17	-0.32
10	DG	0.44	0.46	-0.02
		100.00	100.00	0.00
11	COMPOSITE COST OF GENERATION - CENTRAL STATION ¢/mmbtu	1,056.54	1,052.93	3.61

Source:
Col (A): Settlement and June 2007 Update HECO-WP-934, p. 3.
Col (B): Direct Testimony HECO-WP-934, p. 3.

HAWAIIAN ELECTRIC COMPANY, INC.
Comparison of
Composite Cost of Generation - Central Station and DG
Settlement, June 2007 Update and Direct Testimony

2007 Test Year - Settlement
At Proposed Rates

Line		(A) Settlement and June 2007 Update at Proposed Rates	(B) Direct Testimony at Proposed Rates	(C) Difference (A) - (B)
	CENTRAL STATION			
	FUEL PRICES, ¢/mmbtu			
1	Kahe	1,055.97	1,050.49	5.48
2	Waiau	1,055.65	1,050.17	5.48
3	Honolulu	1,105.93	1,100.18	5.75
4	Diesel	1,707.34	1,698.53	8.81
5	Other	0.00	0.00	0.00
	BTU MIX, %			
6	Kahe	70.31	69.97	0.34
7	Waiau	25.25	25.22	0.03
8	Honolulu	3.58	3.63	-0.05
9	Diesel	0.86	1.18	-0.32
10	Other	0.00	0.00	0.00
		100.00	100.00	0.00
11	COMPOSITE COST OF GENERATION - CENTRAL STATION ¢/mmbtu	1,063.28	1,059.86	3.42
	DG			
	FUEL PRICE, ¢/kwh			
12	COMPOSITE COST OF DG ENERGY ¢/kwh	18.204	18.114	0.090

Source:
Col (A): Settlement and June 2007 Update HECO-WP-936, p. 2 and p. 5.
Col (B): Direct Testimony HECO-WP-936, p. 2 and p. 5.

HAWAIIAN ELECTRIC COMPANY, INC.
Comparison of
Composite Cost of Purchased Energy
Settlement, June 2007 Update and Direct Testimony

2007 Test Year - Settlement
At Present and Proposed Rates

Line		(A) Settlement	(B) June 2007 Update	(C) Direct Testimony	(D) Difference (A)-(B)	(D) Difference (B)-(C)
	PAYMENT RATE, ¢/kwh					
1	Kalaeloa	9.920	9.920	9.919	0.000	0.001
2	AES	2.730	2.690	2.671	0.040	0.019
3	HPower - On Peak	12.782	12.782	12.753	0.000	0.029
4	HPower - Off Peak	9.710	9.710	9.688	0.000	0.022
5	HPower - On Peak-excess	0.000	0.000	0.000	0.000	0.000
6	HPower - Off Peak-excess	9.710	9.710	9.687	0.000	0.023
7	Tesoro - On Peak	14.640	14.640	14.600	0.000	0.040
8	Tesoro - Off Peak	11.080	11.080	11.050	0.000	0.030
9	Chevron - On Peak	14.640	14.640	14.600	0.000	0.040
10	Chevron - Off Peak	11.080	11.080	11.050	0.000	0.030
	KWH MIX, %					
11	Kalaeloa	44.17	44.17	44.16	0.00	0.01
12	AES	45.65	45.65	45.65	0.00	0.00
13	HPower - On Peak	5.83	5.83	5.84	0.00	-0.01
14	HPower - Off Peak	2.69	2.69	2.69	0.00	0.00
15	HPower - On Peak-excess	0.00	0.00	0.00	0.00	0.00
16	HPower - Off Peak-excess	1.48	1.48	1.48	0.00	0.00
17	Tesoro - On Peak	0.09	0.09	0.09	0.00	0.00
18	Tesoro - Off Peak	0.07	0.07	0.07	0.00	0.00
19	Chevron - On Peak	0.01	0.01	0.01	0.00	0.00
20	Chevron - Off Peak	0.01	0.01	0.01	0.00	0.00
		100.00	100.00	100.00	0.00	0.00
21	COMPOSITE COST OF PURCHASED ENERGY, ¢/kwh	6.802	6.783	6.772	0.019	0.0110

Source:
Col (A): Settlement HECO-WP-934, p. 8.
Col (B): June 2007 Update HECO-WP-934, p. 8.
Col (C): Direct Testimony HECO-WP-934, p. 8.

Hawaiian Electric Company, Inc.

Comparison of Sales Heat Rates
Settlement, June 2007 Update and Direct Testimony

(btu/kwh sales)

	Settlement and June 2007 Update [1]	Direct Testimony [2]	Difference
Central Station with Wind/Hydro	11,209	11,225	-16
LSFO	11,143	11,139	4
Diesel	34,955	32,003	2,952
Wind/Hydro	11,209	11,225	-16

1 Settlement, June 2007 Update HECO-WP-936, page 4.
2 Direct Testimony HECO-WP-936 page 4.

Hawaiian Electric Company, Inc.

2007 TEST YEAR ENERGY COST ADJUSTMENT FACTORS
SETTLEMENT

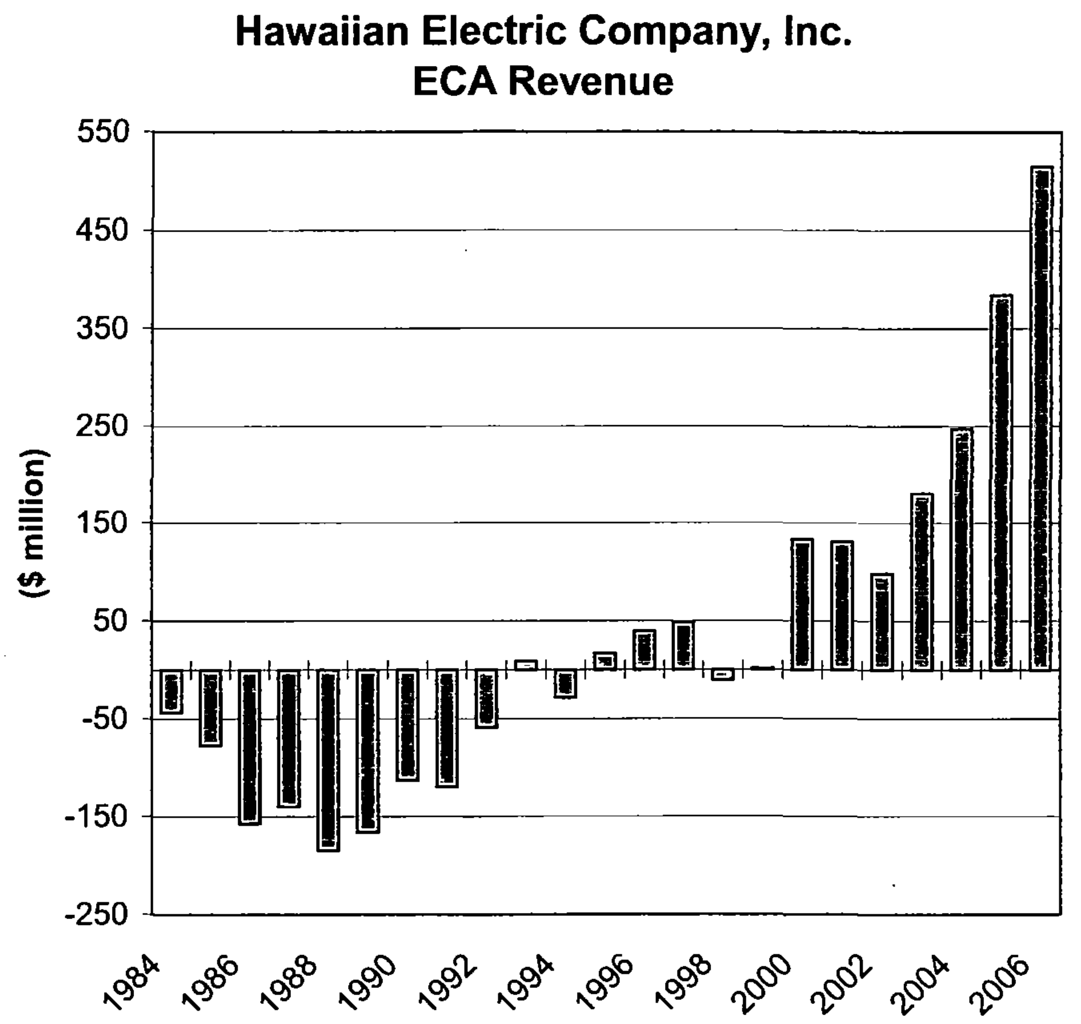
ENERGY COST ADJUSTMENT FACTOR CURRENT EFFECTIVE RATES	ENERGY COST ADJUSTMENT FACTOR PROPOSED RATES
7.340 ¢/KWH	0.000 ¢/KWH

Source: HECO-934, 936

Year	ECA Revenue ($ million) **
1984	-43.408
1985	-77.146
1986	-157.098
1987	-139.662
1988	-184.172
1989	-166.246
1990	-112.381
1991	-119.346
1992	-58.726
1993	8.951
1994	-28.189
1995	16.882
1996	39.733
1997	48.656
1998	-10.042
1999	1.646
2000	133.240
2001	130.984
2002	98.611
2003	180.738
2004	247.831
2005	384.550
2006	514.875

** Includes Revenue Taxes

Note:
Positive values are collections.
Negative values are returns.



* 2006 Sept YTD

HECO T-9
ATTACHMENT 7
PAGE 7 OF 29
FINAL SETTLEMENT

Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING
Present Rates

Line		
1	Effective Date	2007 Test Year - Settlement
2	Supercedes Factor	
	GENERATION COMPONENT	
	FUEL PRICES, ¢/MBTU	
3	Honolulu	1,055.65
4	Kahe	1,055.65
5	Waiau-Steam	1,055.65
6	Waiau-Waste	0.00
7	Waiau-Diesel	1,707.34
8	DG	0.00
	BTU MIX, %	
9	Honolulu	3.56
10	Kahe	70.01
11	Waiau-Steam	25.14
12	Waiau-Waste	0.00
13	Waiau-Diesel	0.85
14	DG	0.44
		100.00
15	COMPOSITE COST OF GENERATION, ¢/MBTU	1,056.54
16	% Input to system kWh Mix	58.41
17	Efficiency Factor, Mbtu/kWh	0.011170
18	WEIGHTED COMPOSITE GEN COST, ¢/KWH (Line 15 x 16 x 17)	6.89329
19	BASE GENERATION COST, ¢/Mbtu	287.83
20	Base % Input to System kWh Mix	58.64
21	Efficiency Factor, Mbtu/kWh	0.011170
22	WEIGHTED BASE GEN COST, ¢/KWH (Line 19 x 20 x 21)	1.88531
23	Cost Less Base (Line 18 - 22)	5.00798
24	Revenue Tax Req Multiplier	1.0975
25	GENERATION FACTOR, ¢/KWH (Line 23 x 24)	5.49626

Line	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE - ¢/KWH			
26	THC	- On Peak		14.640
27		- Off Peak		11.080
28	HRRV	- On Peak		12.782
29		- Off Peak		9.710
30	HRRV	- On Peak	(excess)	0.000
31		- Off Peak	(excess)	9.710
32	Chevron	- On Peak		14.640
33		- Off Peak		11.080
34	Kalaeloa			9.920
35	AES-HI			2.730
	PURCHASED ENERGY KWH MIX, %			
36	THC	- On Peak		0.09
37		- Off Peak		0.07
38	HRRV	- On Peak		5.83
39		- Off Peak		2.69
40	HRRV	- On Peak	(excess)	0.00
41		- Off Peak	(excess)	1.48
42	Chevron	- On Peak		0.01
43		- Off Peak		0.01
44	Kalaeloa			44.17
45	AES-HI			45.65
				100.00
46	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			6.802
47	% Input to System kWh Mix			41.59
48	WTD CMP PURCH ENRGY COST, ¢/KWH (Line 46 x 47)			2.82895
49	BASE PURCH ENERGY COMP COST			3.005
50	Base % Input to System kWh Mix			41.36
51	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 49 x 50)			1.24287
52	Cost Less Base (Line 48 - 51)			1.58608
53	Loss Factor			1.059
54	Revenue Tax Req Multiplier			1.0975
55	PURCHASED ENERGY FACTOR, ¢/KWH (Line 52 x 53 x 54)			1.84343

Line		
56	Fuel & Purchased Energy Factor, ¢/kWh (Line 25 + 55)	7.33969
57	Adjustment, ¢/kWh	0.000
58	ECA Reconciliation Adjustment, ¢/kWh	0.000
59	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 56 + 57 + 58)	7.340

Reference: HECO-WP-934

HAWAIIAN ELECTRIC COMPANY, INC.
Comparison of
Composite Cost of Generation - Central Station
Present Rates and Proposed Rates
2007 Test Year - Settlement

Line		(A) At Present Rates	(B) At Proposed Rates	(C) Difference (B) - (A)
	FUEL PRICES, ¢/mmbtu			
1	Kahe	1,055.65	1,055.97	0.32
2	Waiau	1,055.65	1,055.65	0.00
3	Honolulu	1,055.65	1,105.93	50.28
4	Diesel	1,707.34	1,707.34	0.00
5	DG	0.00		0.00
6	Other		0.00	0.00
	BTU MIX, %			
7	Kahe	70.01	70.31	0.30
8	Waiau	25.14	25.25	0.11
9	Honolulu	3.56	3.58	0.02
10	Diesel	0.85	0.86	0.01
11	DG	0.44		-0.44
12	Other		0.00	0.00
		100.00	100.00	0.00
13	COMPOSITE COST OF GENERATION ¢/mmbtu	1,056.54	1,063.28	6.74

Source:
Col (A): HECO-WP-934, p. 3
Col (B): HECO-WP-936, p. 2

HAWAIIAN ELECTRIC COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Settlement (page 1 of 2)

Line		
1	Effective Date	2007 Test Year - Settlement
2	Supercedes Factors of	

GENERATION COMPONENT

Line	CENTRAL STATION			
	FUEL PRICES, ¢/mmbtu			
3	Honolulu			1,105.93
4	Kahe			1,055.97
5	Waiau-Steam			1,055.65
6	Waiau-Diesel			1,707.34
7	Other			0.00
	BTU MIX, %			
8	Honolulu			3.58
9	Kahe			70.31
10	Waiau-Steam			25.25
11	Waiau-Diesel			0.86
12	Other			0.00
				100.00
13	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu			1,063.28
14	% Input to System kWh Mix			58.15
	EFFICIENCY FACTOR, mmbtu/kWh			
	(A)	(B)	(C)	(D)
	Fuel Type	Eff Factor mmbtu/kwh	Percent of Centrl Stn + Other	Weighted Eff Factor
15	LSFO	0.011143	99.73	0.011113
16	Diesel	0.034955	0.27	0.000096
17	Other	0.011209	0.00	0.000000
	(Lines 15, 16, 17): Col(B) x Col(C) = Col(D)			
18	Weighted Efficiency Factor, mmbtu/kWh [lines 15(D) + 16(D) + 17(D)]			0.011209
19	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (13x14x18))			6.93049
20	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu			1,063.28
21	Base % Input to Sys kWh Mix			58.15
22	Efficiency Factor, mmbtu/kwh			0.011209
23	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (20x21x22))			6.93049
24	COST LESS BASE (line(19-23))			0.00000
25	Revenue Tax Req Multiplier			1.0975
26	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (24x25))			0.00000

DG ENERGY COMPONENT

Line		
27	COMPOSITE COST OF DG ENERGY, ¢/kWh	18.204
28	% Input to System kWh Mix	0.27
29	WTD COMP DG ENRGY COST, ¢/kWh (Lines 27 x 28)	0.04915
30	BASE DG ENERGY COMP COST	18.204
31	Base % Input to System kWh Mix	0.27
32	WTD BASE DG ENERGY COST, ¢/kWh (Line 30 x 31)	0.04915
33	Cost Less Base (Line 29 - 32)	0.00000
34	Loss Factor	1.051
35	Revenue Tax Req Multiplier	1.0975
36	DG FACTOR, ¢/kWh (Line 33 x 34 x 35)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

Line		
37	Cntrl Stn+Other (line 26)	0.00000
38	DG (line 36)	0.00000
39	TOTAL GENERATION FACTOR, ¢/kWh (lines 37 + 38)	0.00000

HAWAIIAN ELECTRIC COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Settlement (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE, ¢/kWh			
40	THC	- On Peak		14.640
41		- Off Peak		11.080
42	HRRV	- On Peak		12.782
43		- Off Peak		9.710
44	HRRV	- On Peak	(excess)	0.000
45		- Off Peak	(excess)	9.710
46	Chevron	- On Peak		14.640
47		- Off Peak		11.080
48	Kalaeloa			9.920
49	AES-HI			2.730
	PURCHASED ENERGY KWH MIX, %			
50	THC	- On Peak		0.09
51		- Off Peak		0.07
52	HRRV	- On Peak		5.83
53		- Off Peak		2.69
54	HRRV	- On Peak	(excess)	0.00
55		- Off Peak	(excess)	1.48
56	Chevron	- On Peak		0.01
57		- Off Peak		0.01
58	Kalaeloa			44.17
59	AES-HI			45.65
				100.00
60	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh			6.802
61	% Input to System kWh Mix			41.58
62	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (60x61))			2.82827
63	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh			6.802
64	Base % Input to Sys kWh Mix			41.58
65	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (63 x 64))			2.82827
66	COST LESS BASE(lines (62 - 65))			0.00000
67	Loss Factor			1.051
68	Revenue Tax Req Multiplier			1.0975
69	PURCHSD ENERGY FCTR, ¢/kWh (lines (66 x 67 x 68))			0.00000

Line	SYSTEM COMPOSITE	
70	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (39 + 69))	0.00000
71	Adjustment, ¢/kWh	0.000
72	ECA Reconciliation Adjustment	0.000
73	ECA FACTOR, ¢/kWh (lines (70 + 71 + 72))	0.000

Reference: HECO-WP-936, HECO-937

Hawaiian Electric Company, Inc.
WEIGHTED COMPOSITE GENERATION COST CALCULATIONS CENTRAL STATION AND OTHER
2007 Test Year - Settlement
At Proposed Rates

	LSFO	Diesel	Other	Total	units
1 Fixed Efficiency Factor	0.011143	0.034955	0.011209		mbtu/kwh
2 Gen Mwh %	99.73	0.27	0.00	100.00	%
round		0.000001			
3 Weighted Efficiency Factor (line 1 x line 2)	0.011113	0.000096	0.000000	0.011209	mbtu/kwh

Reference:
1 HECO-WP-936, page 4.
2 HECO-WP-936, page 3.

Hawaiian Electric Company, Inc.
Fuel Price for ECAC Calculations

2007 Test Year - Settlement

		(A)	(B)	(C)	(D)	(E)	(F)
				Central Station			DG
	Description	Kahe	Waiau	Honolulu	Diesel	Total	Diesel
1	MBtu Consumed	35,380,212	12,708,603	1,801,590	431,808	50,322,213	223,030
2	Fuel Price ($/bbl)	65.4412	65.4412	65.4412	99.9771		99.9771
3	Trucking cost per bbl	0.0000	0.0000	3.1170	0.0000		4.4100
4	Inspection Cost per bbl	0.0092	0.0092	0.0092	0.0730		0.0730
5	Fuel Additive Cost per bbl	0.0198	0.0000	0.0000	0.0000		0.0000
6	Heat Content (MBtu/bbl)	6.2	6.2	6.2	5.86		5.86
	Fuel Price at Present Rates						
7	Fuel Price ($/bbl)						
8	Fuel Oil	65.4412	65.4412	65.4412	99.9771		0.0000
9	Trucking	0.0000	0.0000	0.0000	0.0000		0.0000
10	Inspection	0.0092	0.0092	0.0092	0.0730		0.0000
11	Fuel Additive	0.0000	0.0000	0.0000	0.0000		0.0000
12	Fuel Price ($/bbl)	65.4504	65.4504	65.4504	100.0501		0.0000
13	Fuel Price per MBtu (¢/MBtu)	1,055.65	1,055.65	1,055.65	1,707.34		0.00
	Fuel Price at Proposed Rates						
14	Fuel Price ($/bbl)						
15	Fuel Oil	65.4412	65.4412	65.4412	99.9771		99.9771
16	Trucking	0.0000	0.0000	3.1170	0.0000		4.4100
17	Inspection	0.0092	0.0092	0.0092	0.0730		0.0730
18	Fuel Additive	0.0198	0.0000	0.0000	0.0000		0.0000
19	Fuel Price ($/bbl)	65.4702	65.4504	68.5674	100.0501		104.4601
20	Fuel Price per MBtu (¢/MBtu)	1,055.97	1,055.65	1,105.93	1,707.34		1,782.60

Line 1: HECO-409, page 2
Line 2: HECO-404, pg 1, col B
Line 3: HECO-405, pg 2, col B
Line 4: HECO-405, pg 3, col B
Line 5: Additive $/bbl calculations:
Additive Expense (1) + Kahe bbls consumed (2)
$113,000 + 5,706,486 bbls = 0.0198

(1) HECO-405, pg 1, line 4
(2) HECO-404, pg 1, line 2

Hawaiian Electric Company, Inc.
Determination of Percent of Generation MBTU Mix

2007 Test Year - Settlement
At Present Rates

Line	Generation	(A) MBTU	(B) % to Total Generation	Reference
1	Kahe	35,380,212	70.01	HECO-409 page 2
2	Waiau	12,708,603	25.14	HECO-409 page 2
3	Honolulu	1,801,590	3.56	HECO-409 page 2
4	Diesel	431,808	0.85	HECO-409 page 2
5	DG	223,030	0.44	HECO-409 page 2
6	Total	50,545,243	100.00	HECO-409 page 2

Reference: HECO-WP-934, p.1

HAWAIIAN ELECTRIC COMPANY, INC.
Composite Cost of Generation

2007 Test Year - Settlement
At Present Rates

Line	GENERATION COMPONENT	
	FUEL PRICES, ¢/mmbtu	
1	Kahe	1,055.65
2	Waiau	1,055.65
3	Honolulu	1,055.65
4	Diesel	1,707.34
5	DG	0.00
	BTU MIX, %	
6	Kahe	70.01
7	Waiau	25.14
8	Honolulu	3.56
9	Diesel	0.85
10	DG	0.44
		100.00
11	COMPOSITE COST OF GENERATION, ¢/mmbtu	1,056.54

Line 11: (Line 1x6 + line 2x7 + line 3x8 + line 4x9 + line 5x10)

Reference:
HECO-WP-934, p. 1, line 13
HECO-WP-934, p. 2

Hawaiian Electric Company, Inc.
Net System Percent Mix

2007 Test Year - Settlement
At Present Rates

Line		(A) 2007 Norm Energy (Mwh)	(B) % to Total System	Reference
	Generation (Mwh)			
1	Kahe	3,464,015		HECO-409 page 2
2	Waiau	1,098,623		HECO-409 page 2
3	Honolulu	141,293		HECO-409 page 2
4	Diesel	12,971		HECO-409 page 2
5	DG	21,840		HECO-409 page 2
6	Total Generation	4,738,742	58.41	HECO-409 page 2
	Purchased Power (Mwh)			
7	AES Hawaii, Inc.	1,539,910		HECO-409 page 3
8	Kalaeloa Partners	1,490,246		HECO-409 page 4
9	HPower	337,436		HECO-409 page 5
10	Tesoro	5,304		HECO-RWP-R504
11	Chevron	589		HECO-RWP-R504
12	Total Purchased Power	3,373,485	41.59	HECO-403, line 6
13	Total Net System	8,112,227	100.00	

Hawaiian Electric Company, Inc.
Avoided Energy Cost Payment Rates and Schedule Q

2007 Test Year - Settlement
At Proposed Rates

Avoided Energy Rate - over 100 kW		Source
On-Peak	14.64 ¢/Net Kwh	HECO-WP-934, p. 6
Off-Peak	11.08 ¢/Net Kwh	HECO-WP-934, p. 6.

Schedule Q Payment Rates - Under 100kW		
Payment Rate	12.97 ¢/Net Kwh	HECO-WP-934, p. 7.

Hawaiian Electric Company, Inc.

DERIVATION OF
AVOIDED ENERGY COST PAYMENT RATES
Avoided Energy Rate - over 100 KW

2007 Test Year - Settlement
At Proposed Rates

Line		ON-PEAK	OFF-PEAK	SOURCE
1	Heat Rate	13,382 BTU / NET KWH	9,929 BTU / NET KWH	Docket #4569, HECO-101
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,066.45 ¢ / MMBTU	1,066.45 ¢ / MMBTU	Test Year 2007 Composite Fuel Cost.
3	1 MMBTU / 1,000,000 BTU	1,000,000 BTU / MMBTU	1,000,000 BTU / MMBTU	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	14.27 ¢ / NET KWH	10.59 ¢ / NET KWH	
5	O&M Adjustment	0.37 ¢ / NET KWH	0.49 ¢ / NET KWH	Appendix A, D&O 8298
6	BASE Avoided Energy Payment Rate	14.64 ¢ / NET KWH	11.08 ¢ / NET KWH	

Reference: Line 2: HECO-WP-936, pg. 7, line 7.

Hawaiian Electric Company, Inc.

DERIVATION OF
SCHEDULE "Q" PAYMENT RATES
Schedule "Q" Rate - Under 100 KW

2007 Test Year - Settlement
At Proposed Rates

Line		ON-PEAK	OFF-PEAK	SOURCE
1	Heat Rate	13,382 BTU / NET KWH	9,929 BTU / NET KWH	Docket #7766
2	Composite Fuel Cost of Total Generation (Centrl Stn & DG)	1,066.45 ¢ / MMBTU	1,066.45 ¢ / MMBTU	Test Year 2007 Composite Fuel Cost.
3	1 MMBTU / 1,000,000 BTU	1,000,000 BTU / MMBTU	1,000,000 BTU / MMBTU	
4	Unadjusted Payment Rate (line 1 x 2) / line 3	14.27 ¢ / NET KWH	10.59 ¢ / NET KWH	
5	Power Factor Adjustment	-0.12 ¢ / NET KWH	-0.28 ¢ / NET KWH	Appendix A, D&O 8298
6	O&M Adjustment	0.37 ¢ / NET KWH	0.49 ¢ / NET KWH	Appendix A, D&O 8298
7	Pre Time-Weighted "Q" Payment Rate (line 4 + line 5 + line 6)	14.52 ¢ / NET KWH	10.80 ¢ / NET KWH	
8	Hour Weighting	x 14/24 HOURS / HOURS	x 10/24 HOURS / HOURS	
9	Time-weighted Peak Time-Related Schedule "Q" Energy Payment Rate (line 7 x 8)	8.47 ¢ / NET KWH	4.50 ¢ / NET KWH	

Line			SOURCE
10	Time-Weighted "Q" ON PEAK Payment Rate	8.47 ¢ / NET KWH	
11	Time-Weighted "Q" OFF PEAK Payment Rate	4.50 ¢ / NET KWH	
12	Schedule "Q" Energy Payment Rate (line 10 + line 11)	12.97 ¢ / NET KWH	
13	Base 1996 Schedule "Q" Energy Payment	3.67 ¢ / NET KWH	Filed January 1, 1996
14	Difference Between 2007 Test Year Update and Base Sch "Q" Rates (line 12 - line 13)	9.30 ¢ / NET KWH	

Reference: Line 2: HECO-WP-936, pg. 7, line 7.

Hawaiian Electric Company, Inc.
Determination of Percent of Purchased Energy Mix,
Payment Rate (in ¢/kwh) and
Composite Cost of Purchased Energy (in ¢/kwh)

2007 Test Year - Settlement
At Present and Proposed Rates

No.	(A) Producer	(B) Gwh Purchased	(C) % to Total PP	(D) Payment Rate (¢/kwh)	(E) Weighted Cost (¢/kwh) [(colF + colB) * colC * 1000]	(F) Purch Pwr Fuel Expense ($ thous)
1	**Kalaeloa**					
	Fuel	1,490.2	44.17	9.760		145,448.6
	Additive			0.160		2,386.4
	Total	1,490.2		9.920	4.382	147,835.0
2	**AES**					
	Fuel	1,539.9	45.65	2.730	1.246	42,037.2
3	**HPower**					
	On Peak	196.8	5.83	12.782	0.745	25,159.8
	Off Peak	90.6	2.69	9.710	0.261	8,798.2
	On Peak - excess	0.0	0.00	0.000	0.000	0.0
	Off Peak - excess	50.0	1.48	9.710	0.144	4,853.9
	Total	337.4				38,811.9
4	**Tesoro**					
	On Peak	3.1	0.09	14.640	0.013	453.0
	Off Peak	2.2	0.07	11.080	0.008	244.9
	Total	5.3				697.9
5	**Chevron**					
	On Peak	0.4	0.01	14.640	0.001	50.3
	Off Peak	0.2	0.01	11.080	0.001	27.2
	Total	0.6				77.5
6	**Other**	-	-	0.000	0.000	-
7	Total	3,373.5	100.00		6.802	229,459.5
8	Composite Cost of Purchased Energy				6.802 ¢/kwh	

= settlement change

Line 1: HECO-WP-501, pg. 1
Line 2: HECO-WP-503, pg. 1
Line 3: HECO-WP-504, pg. 2
Lines 4&5: HECO-504
Line 7, col B: HECO-403, line 6

Hawaiian Electric Company, Inc.
Determination of Percent of Central Station Generation MBTU Mix

2007 Test Year - Settlement
At Proposed Rates

Line	Central Station Plant	(A) MBTU	(B) % to Total Generation	Reference
1	Kahe	35,380,212	70.31	HECO-409 page 2
2	Waiau	12,708,603	25.25	HECO-409 page 2
3	Honolulu	1,801,590	3.58	HECO-409 page 2
4	LSFO total	49,890,405	99.14	
5	Diesel	431,808	0.86	HECO-409 page 2
6	Total	50,322,213	100.00	HECO-409 page 2

HAWAIIAN ELECTRIC COMPANY, INC.
Composite Cost of Central Station Generation

2007 Test Year - Settlement
At Proposed Rates

Line	GENERATION COMPONENT Central Station and Other	
	FUEL PRICES, ¢/mmbtu	
1	Kahe	1,055.97
2	Waiau	1,055.65
3	Honolulu	1,105.93
4	Diesel	1,707.34
5	Other	0.00
	BTU MIX, %	
6	Kahe	70.31
7	Waiau	25.25
8	Honolulu	3.58
9	Diesel	0.86
10	Other	0.00
		100.00
11	COMPOSITE COST OF GENERATION, Central Stn + Other ¢/mmbtu	1,063.28

Line 11: (Line 1x6 + line 2x7 + line 3x8 + line 4x9 + line 5x10)

Reference:
HECO-WP-934, p. 1, line 20
HECO-WP-936, p. 1

Hawaiian Electric Company, Inc.
Percent of Central Station LSFO and Diesel Kwh Mix

2007 Test Year - Settlement
At Proposed Rates

Line			(A) 2007 Norm Energy (Mwh)	(B) Percent of Central Stn Generation	Reference
1	Kahe		3,464,015		HECO-409 page 2
2	Waiau		1,098,623		HECO-409 page 2
3	Honolulu		141,293		HECO-409 page 2
4		LSFO Total	4,703,931	99.73	
5	Diesel		12,971	0.27	HECO-409 page 2
6	Total		4,716,902	100.00	HECO-409 page 2

Hawaiian Electric Company, Inc.
Determination of Fixed Efficiency Factor or Sales Heat Rate (Mbtu / Kwh Sales)
2007 Test Year - Settlement
At Proposed Rates

Line				Reference
	Total Central Station Fuel Sales Heat Rate			
1	Total Central Station Fuel Consumed	50,322,213	Mbtu	HECO-409 page 2
2	Sales	7,720.8	Gwh	HECO-403, line 1
3	% of Central Stn to Total System	58.15	Percent	HECO-403, line 7a
4	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
5	Sales Heat Rate [line 1 ÷ (line 2 x line 3 x line 4)]	0.011209	Mbtu/Kwh Sales	
	LSFO Sales Heat Rate			
6	LSFO Fuel Consumed	49,890,405	Mbtu	HECO-409 page 2
7	Sales	7,720.8	Gwh	HECO-403, line 1
8	% of LSFO Fuel Generation to Total System	57.99	Percent	HECO-936 page 8
9	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
10	Sales Heat Rate [line 6 ÷ (line 7 x line 8 x line 9)]	0.011143	Mbtu/Kwh Sales	
	Diesel Fuel Sales Heat Rate			
11	Diesel Fuel Consumed	431,808	Mbtu	HECO-409 page 2
12	Sales	7,720.8	Gwh	HECO-403, line 1
13	% of Diesel Fuel Generation to Total System	0.16	Percent	HECO-936 page 8
14	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
15	Sales Heat Rate [line 11 ÷ (line 12 x line 13 x line 14)]	0.034955	Mbtu/Kwh Sales	
	HECO Other Sales Heat Rate			
16	Total Central Station Fuel Consumed	50,322,213	Mbtu	
17	Sales	7,720.8	Gwh	
18	% of Central Stn to Total System	58.15	Percent	
19	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
20	Sales Heat Rate [line 16 ÷ (line 17 x line 18 x line 19)]	0.011209	Mbtu/Kwh Sales	

Hawaiian Electric Company, Inc.
Determination of Composite Cost of DG Energy

2007 Test Year - Settlement
At Proposed Rates

	(A)	(B)	(C)	(D)	(E) (colD ÷ colC x 100)	(F) (colD ÷ colB x 100)
Line	DG Unit Location	Net to System (Kwh)	Fuel Consumed (Mbtu)	Fuel Expense ($)	Fuel Cost (¢/mbtu)	Fuel Cost (¢/kwh)
1	Substation DG	21,840,000	223,030	3,975,733	1782.60	18.204
2					0.00	0.000
3					0.00	0.000
4					0.00	0.000
5	Total	21,840,000	223,030	3,975,733	1782.60	18.204

Line		
6	Composite DG Fuel Cost	1782.60 ¢/mbtu
7	Composite Cost of DG Energy	18.204 ¢/kwh

Col B: HECO-409 page 2
Col C: HECO-409 page 2
Col D: HECO-404 page 2

Hawaiian Electric Company, Inc.
Determination of Central Station and DG Percent to Total Generation Mbtu Mix

2007 Test Year - Settlement
At Proposed Rates

		(A) 2007 Mbtu Consumed	(B) % to Total Mbtu Consumed	Reference
1	Central Station Generation	50,322,213	99.56	HECO-409 page 2
2	DG	223,030	0.44	HECO-409 page 2
3	Total Generation	50,545,243	100.00	

Hawaiian Electric Company, Inc.
Determination of Composite Cost of Total (Central Station and DG) Generation
For Avoided Cost Calculation Purposes

2007 Test Year - Settlement
At Proposed Rates

Line	CENTRAL STATION ENERGY COMPONENT		Line	DG ENERGY COMPONENT	
1	Composite Cost of Centrl Stn Gen.	1063.28 ¢/Mbtu	4	Composite Cost of DG Generation	1782.60 ¢/Mbtu
2	Percent of Centrl Stn Gen. Btu Mix	99.56 %	5	Percent of DG Gen. Btu Mix (100 - line 3)	0.44 %
3	Weighted Composite Cost of Central Station (line 1 x line 2)	1058.6016 ¢/Mbtu	6	Weighted Composite Cost of DG (line 4 x line 5)	7.8434 ¢/Mbtu

Line	Total Generation Composite Cost	
7	Composite Cost of Central Station and DG (line 3 + line 6)	1066.45 ¢/Mbtu

Line 1: HECO-WP-936 page 2, line 11
Line 2: HECO-WP-936 page 6, line 1 col.(B)
Line 4: HECO-WP-936 page 5, line 6
Line 5: HECO-WP-936 page 6, line 2 col.(B)

Hawaiian Electric Company, Inc.
Net System Percent Mix

2007 Test Year - Settlement
At Proposed Rates

		(A) 2007 Norm Energy (Gwh)	(B) % to Total System	Reference
	Central Station Generation			
	LSFO	4,704.7	57.99	
	Diesel	13.0	0.16	
12	Tot Central Station Generation	4,717.7	58.15	HECO-403, line 7a
13	DG	21.8	0.27	HECO-403, line 7b
14	Purchase Power	3,373.5	41.58	HECO-403, line 6
15	Total Net System	8,113.0	100.00	HECO-403, line 5

Hawaiian Electric Company, Inc.
DG and Purchased Energy Loss Factor Calculations

2007 Test Year - Settlement
At Proposed Rates

Line			Reference
1	Net to System (gwh)	8,113.0	HECO-403, line 5
2	Sales (gwh)	7,720.8	HECO-403, line 1
3	DG & Purchase Power Loss Factor	1.051	Line 1 + Line 2

Attachment 8
Regular HECO Employees
Incremental DSM Labor Hours and Expenses

Line			(150) Hours	SLR	Total	(421) NPW	NPW	(406) Corp Adm	Corp Adm	(422) Emp Ben	Emp Ben	(423) PR taxes	PR taxes	(150) + (421) Labor	Non-Labor	TOTAL
1	PM Commercial	CIEE	1,102.00	32.79	36,134.58	4.26	4,694.52	3.73	4,110.46	12.30	13,554.60	0.0818	2,955.81	40,829.10	20,620.87	61,449.97
2	CEP Analyst	CIEE	602.00	32.79	19,739.58	4.26	2,564.52	3.73	2,245.46	12.30	7,404.60	0.0818	1,614.70	22,304.10	11,264.76	33,568.86
3	CEP Analyst	CIEE	324.00	32.79	10,623.96	4.26	1,380.24	3.73	1,208.52	12.30	3,985.20	0.0818	869.04	12,004.20	6,062.76	18,066.96
4	Total	CIEE	2,028.00		66,498.12		8,639.28		7,564.44		24,944.40		5,439.55	75,137.40	37,948.39	113,085.79
5	PM Commercial	CINC	543.00	32.79	17,804.97	4.26	2,313.18	3.73	2,025.39	12.30	6,678.90	0.0818	1,456.45	20,118.15	10,160.74	30,278.89
6	CEP Analyst	CINC	602.00	32.79	19,739.58	4.26	2,564.52	3.73	2,245.46	12.30	7,404.60	0.0818	1,614.70	22,304.10	11,264.76	33,568.86
7	CEP Analyst	CINC	324.00	32.79	10,623.96	4.26	1,380.24	3.73	1,208.52	12.30	3,985.20	0.0818	869.04	12,004.20	6,062.76	18,066.96
8	Total	CINC	1,469.00		48,168.51		6,257.94		5,479.37		18,068.70		3,940.18	54,426.45	27,488.25	81,914.70
9	PM Commercial	CICR	176.00	32.79	5,771.04	4.26	749.76	3.73	656.48	12.30	2,164.80	0.0818	472.07	6,520.80	3,293.35	9,814.15
10	CEP Analyst	CICR	620.00	32.79	20,329.80	4.26	2,641.20	3.73	2,312.60	12.30	7,626.00	0.0818	1,662.98	22,971.00	11,601.58	34,572.58
11	CEP Analyst	CICR	324.00	32.79	10,623.96	4.26	1,380.24	3.73	1,208.52	12.30	3,985.20	0.0818	869.04	12,004.20	6,062.76	18,066.96
12	Total	CICR	1,120.00		36,724.80		4,771.20		4,177.60		13,776.00		3,004.09	41,496.00	20,957.69	62,453.69
13	PM Residential	REWH	753.00	32.79	24,690.87	4.26	3,207.78	3.73	2,808.69	12.30	9,261.90	0.0818	2,019.71	27,898.65	14,090.30	41,988.95
14	CEP Analyst	REWH	324.00	32.79	10,623.96	4.26	1,380.24	3.73	1,208.52	12.30	3,985.20	0.0818	869.04	12,004.20	6,062.76	18,066.96
15	Total	REWH	1,077.00		35,314.83		4,588.02		4,017.21		13,247.10		2,888.75	39,902.85	20,153.06	60,055.91
16	PM Residential	RNC	368.00	32.79	12,066.72	4.26	1,567.68	3.73	1,372.64	12.30	4,526.40	0.0818	987.06	13,634.40	6,886.10	20,520.50
17	CEP Analyst	RNC	318.00	32.79	10,427.22	4.26	1,354.68	3.73	1,186.14	12.30	3,911.40	0.0818	852.95	11,781.90	5,950.49	17,732.39
18	Total	RNC	686.00		22,493.94		2,922.36		2,558.78		8,437.80		1,840.00	25,416.30	12,836.58	38,252.88
19	PM Residential	ESH	367.00	32.79	12,033.93	4.26	1,563.42	3.73	1,368.91	12.30	4,514.10	0.0818	984.38	13,597.35	6,867.39	20,464.74
20	Total	ESH	367.00		12,033.93		1,563.42		1,368.91		4,514.10		984.38	13,597.35	6,867.39	20,464.74
21	PM Residential	RLI	374.00	32.79	12,263.46	4.26	1,593.24	3.73	1,395.02	12.30	4,600.20	0.0818	1,003.15	13,856.70	6,998.37	20,855.07
22	Total	RLI	374.00		12,263.46		1,593.24		1,395.02		4,600.20		1,003.15	13,856.70	6,998.37	20,855.07
23	Total		7,121.00													397,082.78
	HECO Update Adjustment															
24	CEP Analyst	REWH	67.00	32.79	2,196.93	4.26	285.42	3.73	249.91	12.30	824.10	0.0818	179.71	2,482.35	1,253.72	3,736.07
25		RNC	40.00	32.79	1,311.60	4.26	170.40	3.73	149.20	12.30	492.00	0.0818	107.29	1,482.00	748.49	2,230.49
26			107.00		3,508.53		455.82		399.11		1,316.10		287.00	3,964.35	2,002.21	5,966.56
27	C&I Engineer	CICR	1,904.00	32.79	62,432.16	4.26	8,111.04	3.73	7,101.92	12.30	23,419.20	0.0818	5,106.95	70,543.20	35,628.07	106,171.27
28			1,904.00		62,432.16		8,111.04		7,101.92		23,419.20		5,106.95	70,543.20	35,628.07	106,171.27
29	Total		2,011.00													112,137.83
30	Grand Total		9,132.00													509,220.61
	PAYS															
31	CEP Analyst	PAYS	614.00	32.79	20,133.06	4.26	2,615.64	3.73	2,290.22	12.30	7,552.20	0.0818	1,646.88	22,748.70	11,489.30	34,238.00
32	**Total with PAYS**		**9,746.00**		**319,571.34**		**41,517.96**		**36,352.58**		**119,875.80**		**26,140.94**	**361,089.30**	**182,369.32**	**543,458.62**

HECO T-9
ATTACHMENT 8
PAGE 1 OF 1
FINAL SETTLEMENT

Hawaiian Electric Company, Inc.
Docket No. 2006-0386
Test Year 2007
Abandoned Projects

	Direct Testimony	Adj	Settlement Proposal (See response to CA-IR-492)	Add'tl Adj	CA's Proposed Adj. C-19	CA/HECO Agreed Upon Amounts
	(a)	(b)	(c)	(d)	(e)	(f)
					(b+d)	(c-d)
Production	42	-8	34	-10	-18	24
Transmission	23	-2	21	-8	-10	13
Distribution	123	-24	99	-27	-51	72
Customer Account	30	-7	23	-6	-13	17
A&G	6	**2**	8	**-4**	**-2**	4
Total	224	-39	185	-55	-94	130

PENSION TRACKING MECHANISM

Purpose: The proposed pension tracking mechanism is designed to achieve the following objectives:

A. Ensure that the pension costs recovered through rates are based on the FAS87 NPPC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the pension trust funds (subject to the exceptions in Item 3 below) are in an amount equal to actual NPPC (after the pension asset is reduced to zero as provided in Item 2 below) and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS87, FAS158 or any other FASB statement or procedure relative to the recognition of pension costs and/or liabilities.

Procedure:

1. The amount of FAS87 NPPC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Until the pension asset is reduced to zero, the Company would be required to fund the minimum required level under the law. Thereafter, except when limited by the ERISA minimum contributions requirements or the maximum contribution imposed by the IRC, or the contribution exceeds the NPPC for a reason provided in Item 3, the annual contribution to the pension trust fund will be equal to the amount of FAS87 NPPC.

3. The utility will be allowed to recover through rates the amount of any contributions to the pension trust in excess of the FAS87 NPPC that were made for the following reasons[1]:

    - the minimum required contribution is greater than the FAS 87 NPPC,

    - the increased contribution was made to avoid a significant increase in Pension Benefit Guaranty Corporation (PBGC) variable premiums,

    - the increased contribution was made to avoid a charge to other comprehensive income, or

---

[1] The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

- the increased contribution was made to avoid: (i) higher minimum contribution requirements under the Pension Protection Act,[2] or (ii) other adverse funding requirements under federal pension regulations (provided funding does not exceed 100% of the PBO as a result). The recoverability of any discretionary contributions (as described under this bullet item) shall be subject to review in the Company's next rate case.

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS87 NPPC during the rate effective period and the level of FAS87 NPPC included in rates during that same period.

    - The amortization of any unamortized cumulative net ratepayer benefit at the end of the test year in the next HECO rate case shall be determined in that rate case proceeding.

    - If the actual FAS87-determined NPPC recorded during a given rate-effective period is greater than the FAS87 NPPC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is <u>not</u> used to reduce a regulatory liability recorded pursuant to Item 5.

    - If the actual FAS87-determined NPPC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

    - If the actual FAS87 NPPC becomes negative, the regulatory liability will be increased by the difference between the level of FAS87 NPPC included in rates for that period and "zero" (i.e., $0).

    - Since this is considered to be a <u>cash</u> item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

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[2] Transitional relief applies under the Pension Protection Act if the plan's target liability funded level meets the prescribed phase-in percentages for 2008 through 2011. The Parties recognize that such transitional relief or related requirements may be subject to change or revision in future years.

5. If the FAS87 NPPC becomes negative, the Company will set up a regulatory liability to offset the prepaid pension asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPPC, or decrease by the amount of positive NPPC, in each subsequent year. Positive NPPC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

    - If NPPC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).
    - If NPPC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).
    - Since this regulatory liability is considered to be a <u>non-cash</u> item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS87-based NPPC, including the amortization of unrecognized amounts as set forth above.

    - The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan.
    - This regulatory asset/liability will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS87 NPPC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS87 and, pursuant to other provisions of this proposal, all FAS87-determined NPPC will over time ultimately be recovered from ratepayers.
    - The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless of whether the term is longer or shorter than five years.

    - The Company will be required to establish a separate regulatory asset or liability to accumulate any excess negative amortization or positive amortization (separate from the pension asset existing at the adoption of the tracking mechanism), which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any prepaid pension asset or accrued liability recorded pursuant to the terms and conditions of FAS87 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will <u>not</u> be included in Rate Base in any future rate case, except for the cumulative net ratepayer benefits previously identified is allowed by the Commission. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for pension differences.

Comments & Clarifications
Proposed Pension Tracking Mechanism

1. The proposed tracking mechanism refers to "NPPC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS87 <u>net periodic costs</u>.

2. "NPPC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.

3. Unless limited by IRC maximum contributions or ERISA minimum contributions, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 <u>net periodic costs</u> determined for each calendar year.

4. The proposed tracking mechanism requires the Company to establish a <u>regulatory</u> asset or liability for the difference between the total FAS87 <u>net periodic costs</u> determined for a given year and the amount of such costs included in then-existing utility rates.

5. The provisions of FAS87 may require a Company to record a prepaid pension asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any future prepaid pension asset resulting from an actuarial study that resulted in "negative" net periodic costs.

b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS87 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, when the Company is required to fund the NPPC, the Company would be required to commit to funding 100% of the FAS87 net periodic costs for both HECO and the affiliate **or** to maintain segregated pension trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise in the future.

7. Any commitment by HECO to fund 100% of its FAS87 net periodic costs (when required under item 2 or as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each HECO affiliate.

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2006

NARUC Operating Expense Category	% of Dues
Legislative Advocacy	20.39%
Legislative Policy Research	5.34%
Regulatory Advocacy	16.47%
Regulatory Policy Research	15.33%
Advertising	1.29%
Marketing	3.94%
Utility Operations and Engineering	11.76%
Finance, Legal, Planning and Customer Service	16.67%
Public Relations	8.81%
Total Expenses	100.00%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2006, the lobbying % for IRS reporting is 18.9%.

* Administrative expenses are included in the percentages listed above. Approximately 9% of EEI's core dues expenses are administrative.

EEI 2006 NARUC Operating Expense Category	% of Dues
Legislative Advocacy	20.39%
Legislative Policy Research	5.34%
Advertising	1.29%
Marketing	3.94%
Public Relations	8.81%
Total Excluded Expenses (see Attachment 1)	39.77%
Total Excluded Expenses (rounded)	40.00%
Adjustment for Government Lobbying - Direct Testimony (N.1)	25.00%
Difference	15.00%
Membership Dues for Regular Activities (N.1)	$244,580
Additional Adjustment for Government Lobbying	$36,687

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Miscellaneous Administrative and General (A&G) Expenses
Research and Development (R&D)
2007 Test Year

Projects:	
Electrical System Analysis	$164,000
AMI	$404,000
CPP/PTR	$60,000
LCR	$60,000
Biofuel Feedstock Study	$92,000
Grid Code Review	$26,000
Biofuel Crop Study	$50,000
Total Projects	$856,000
EPRI Membership Dues	$1,608,000
TOTAL R&D	$2,464,000

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386
CUSTOMER SERVICE EXPENSE LABOR ADJ
FOR THE FORECAST 2007 TEST YEAR

			Average Staffing Calculations				Adjustment	HECO-912	Direct Labor
LINE NO.	RA	Division	Updated 2007 TY	Actual 12/31/2006	Average	Difference	Percentage Difference	Direct Labor Forecast	O&M Adjustment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	PSA	Administration	3	3	3.0	-	**0.0%**	$ 35,000	$ -
2	PSR	Cust. Technol. Applic.	10	8	9.0	(1.0)	**-10.0%**	379,000	(37,900)
3	PSN	Marketing Svcs.	12	11	11.5	(0.5)	**-4.2%**	809,000	(33,708)
4	PSM	Forecasts/Research	10	10	10.0	-	**0.0%**	337,000	-
5	PQC	Corporate Commun.	9	8	8.5	(0.5)	**-5.6%**	233,000	(12,944)
6	PQE	Education/Consumer Aff	8	8	8.0	-	**0.0%**	377,000	-
7		**TOTAL ACCOUNT 910**	52.0	48.0	50.0	(2.0)		2,170,000	(84,553)

8	**Adjustment to Normalize Customer Accounts Expenses**	**$ (84,553)**
9	**Adjustment to Normalize Customer Accounts Expenses (Rounded 000's)**	**$ (85)**

NOTE: Adjusted to reflect Final Settlement made to CA Exhibit CA-101, Schedule C-10:
PSM = 1 Actual HC added. Planning Analyst position filled on 1/15/07.

Footnotes:

(a) Sources: column C is from CA-IR-465
column D is from CA-IR-27, page 17
column H is from HECO-912

(b) This adjustment is limited to Account 910, where most labor expenses are recorded and does not include various other RA's that contribute only $37,000 in total labor charges to Account 910.

LINE NO.	RA	Division	Average Staffing Calculations: Updated 2007 TY	Actual 12/31/2006	Average	Difference	Adjustment Percentage Difference	HECO Direct Labor Forecast	T&D Direct Labor O&M Adjustment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	PDA	Administration	6	5	5.5	(0.5)	-8.3%	$ 508	$ (42)
2	PDC	Control Section	6	5	5.5	(0.5)	-8.3%	46,395	(3,866)
3	PDF	Field Operation	23	24	23.5	0.5	2.2%	1,387,022	30,153
4	PDS Note (b)	Operations	160	161	160.5	0.5	0.3%	4,383,654	13,699
5		**C&M**	195	195	195.0	-		5,817,579	39,943
6	PBZ	T&D Tech Services	8	7	7.5	(0.5)	-6.3%	19,444	(1,215)
7		**ENGINEERING**	8	7	7.5	(0.5)		19,444	(1,215)
8	PVM	Materials Management	28	27	27.5	(0.5)	-1.8%	48,518	(866)
9		**SUPPORT SERVICES**	28	27	27.5	(0.5)		48,518	(866)
10	PRA	Administration	7	7	7.0	-	0.0%	29,297	-
11	PRD	Operating Dispatch	27	23	25.0	(2.0)	-7.4%	1,801,029	(133,410)
12	PRE	Operating Engineering	14	11	12.5	(1.5)	-10.7%	736,924	(78,956)
13	PRS	Substation	39	37	38.0	(1.0)	-2.6%	1,830,541	(46,937)
14		**SYSTEM OPERATIONS**	87	78	82.5	(4.5)		4,397,792	(259,303)
15	P2V	VP Energy Delivery	2	2	2.0	-	0.0%	140,673	-
16		**VP-EN DEL**	2	2	2.0	-		140,673	-
17	PWA	EN Sol-Admin	12	11	11.5	(0.5)	-4.2%	50,874	(2,120)
18	PWP	EN Sol-Planning & Design	27	21	24.0	(3.0)	-11.1%	167,120	(18,569)
19	PWX	EN Sol-Engineering & Meter	14	12	13.0	(1.0)	-7.1%	460,401	(32,886)
20	PCB	Cust Svc-Cust Acctg & Bill	6	6	6.0	-	0.0%	1,184	-
21	PCF	Cust Svc-Customer Field Svcs	5	5	5.0	-	0.0%	9,091	-
22	PCG	Cust Svc-Fld Svc & Collection	26	26	26.0	-	0.0%	312,655	-
23	PCM	Cust Svc-Meter Reading	34	34	34.0	-	0.0%	17,055	-
24	PCS	Cust Svc-Customer Acct Svcs	5	5	5.0	-	0.0%	1,727	-
25	PSD	Cust Sol-Cust Efficiency Pgms	11	11	11.0	-	0.0%	32,790	-
26	PNC	Legal-Legal	11	11	11.0	-	0.0%	38,628	-
27	PHB	Corp Excel-Facilities Operation	15	14	14.5	(0.5)	-3.3%	239,119	(7,971)
28	PHF	Corp Excel-Facilities Planning	8	7	7.5	(0.5)	-6.3%	426	(27)
29		**OTHER DEPARTMENTS**	178	167	172.5	(5.5)		1,610,417	(61,572)
30	Total T&D O&M		498 (a)	476 (a)	487.0	(11.0)	-2.2%	$ 12,034,422 (c)	$ (283,013)

LINE NO.			
31	Total T&D O&M Direct Labor Adjustment	(000's)	$ (283)
32	Add: Indirect On-Costs	(d)	11.6%
33	Direct Labor Times On-Cost Percentage		(33)
34	Total Adjustment to Normalize for Average Staffing in T&D Department		$ (316)

Footnotes:

(a) Source: Staffing levels from CA-IR-465, CA-IR-27 & CA-IR-100.

(b) In response to CA-IR-465, HECO's forecast combined the headcounts for RAs PDD, PDJ, PDK, PDL and PDU into PDS.

(c) Source: HECO direct labor T&D forecast from CA-IR-1 (T-7), Attachment A.

(d) Indirect costs:

	Transmission	Distribution	Total
Direct $	$ 4,017,576	$ 9,626,378	$ 13,643,954
Oncost $	451,286	1,125,219	1,576,505
Total Labor $	$ 4,468,862	$ 10,751,597	$ 15,220,459
Oncost %	11.2%	11.7%	11.6%

Source: HECO-WP-101(F) & (H).

NOTE: Adjusted to reflect Final Settlement made to CA Exhibit CA-101, Schedule C-13:

PRA = 1 Actual HC added. Director, Special Projects, position filled on 1/8/07.

PRD = 1 Actual HC added. Temps hired from January through present (and planned throughout the rest of year). Unbudgeted contractor costs of approximately $85K incurred to date.

PRE = 1 Actual HC added. Outside contractors used to perform work. Approximately $107K of unbudgeted contractor costs incurred from 1/07 through now.

P2V = Correction of error in HC numbers. No change to CA's proposed labor adjustment.

PCF = 1 Actual HC added. HECO Temp hired on 1/22/07 to cover vacancy work.

PCM = 1 Actual HC added. Meter Reader position filled on 1/22/07

PSD = 1 Actual HC added. Program Engineer started 1/22/07.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386
PAYROLL EXPENSE (A/C 920)
FOR THE FORECAST 2007 TEST YEAR

LINE NO.	RA	Division	Average Staffing Calculations: Updated 2007 TY	Average Staffing Calculations: Actual 12/31/2006	Average Staffing Calculations: Average	Average Staffing Calculations: Difference	Adjustment Percentage Difference	HECO Direct Labor Forecast	A&G A/C 920 Direct Labor O&M Adjustment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	PFB	Comp & Ben-Empl Benef	10	9	9.5	(0.5)	-5.0%	$ 22,855	$ (1,143)
2	PHB	Safety,Secur-Facilities Ops	15	14	14.5	(0.5)	-3.3%	569,867	(18,996)
3	PHF	Safety,Secur-Facilities Planning	8	7	7.5	(0.5)	-6.3%	314,540	(19,659)
4	PHS	Safety,Secur-Security	10	8	9.0	(1.0)	-10.0%	427,350	(42,735)
5	PFA	Workforce & Dev-Admin	4	4	4.0	-	0.0%	177,152	-
6		**CORPORATE EXCELLENCE**	47	42	44.5	(2.5)		1,511,764	(82,532)
7	PQC	Corporate Communications	9	8	8.5	(0.5)	-5.6%	309,567	(17,198)
8		**CORPORATE RELATIONS**	9	8	8.5	(0.5)		309,567	(17,198)
9	PSD	Energy Svs-Cust Efficiency Progs	11	10	10.5	(0.5)	-4.5%	10,927	(497)
10	PSP	Energy Svs-Pricing	5	5	5.0	-	0.0%	240,055	-
11	PSM	Forecasts & Research	10	10	10.0	-	0.0%	163,723	-
12		**CUSTOMER SOLUTIONS**	26	25	25.5	(0.5)		414,706	(497)
13	PVF	Sup Svs - Fleet	25	21	23.0	(2.0)	-8.0%	333	(27)
14	PVM	Sup Svs - Materials Man	28	27	27.5	(0.5)	-1.8%	18,118	(324)
15	PVP	Sup Svs - Purchasing	15	14	14.5	(0.5)	-3.3%	747,457	(24,915)
16		**ENERGY DELIVERY**	68	62	65.0	(3.0)		765,908	(25,265)
17	PEC	ITS-Customer Care	23	25	24.0	1.0	4.3%	155,892	6,778
18	PED	ITS-Development Svs	37	36	36.5	(0.5)	-1.4%	77,857	(1,052)
19	PEI	ITS-Infrastructure & Ops	24	22	23.0	(1.0)	-4.2%	103,334	(4,306)
20	PEM	ITS-Mailing Svs	8	10	9.0	1.0	12.5%	294,306	36,788
21		**FINANCE**	92	93	92.5	0.5		631,389	38,208
22	PNP	Regulatory Affairs	15	15	15.0	-	0.0%	677,475	-
23		**GOV'T & COMMUNITY AFFAIRS**	15	15	15.0	-		677,475	-
24	PJB	Environmental-Air Quality	6	5	5.5	(0.5)	-8.3%	34,255	(2,855)
25	PJW	Environmental-Water & Haz Mat	8	7	7.5	(0.5)	-6.3%	59,743	(3,734)
26	PIB	Production-Admin-PS O&M	9	8	8.5	(0.5)	-5.6%	6,026	(335)
27		**POWER SUPPLY**	23	20	21.5	(1.5)		100,024	(6,923)
28	PNA	Corp Audit-Internal Audit	8	7	7.5	(0.5)	-6.3%	361,919	(22,620)
29	PNX	Corp Audit-Admin	4	3	3.5	(0.5)	-12.5%	235,265	(29,408)
30	P9P	President	3	2	2.5	(0.5)	-16.7%	562,451	(93,742)
31		**PRESIDENT**	15	12	13.5	(1.5)		1,159,635	(145,770)
32	PNG	Energy Projects	9	8	8.5	(0.5)	-5.6%	135,579	(7,532)
33		**SR VP-ENERGY SOLUTIONS**	9	8	8.5	(0.5)		135,579	(7,532)
34	P8V	Sr. VP-Operations	2	3	2.5	0.5	25.0%	335,262	83,816
35	*partial list*	**SR VP-OPERATIONS**	2	3	2.5	0.5		335,262	83,816
36	PNI	Government Relations	3	3	3.0	-	0.0%	205,875	-
37		**SR VP-PUBLIC AFFAIRS**	3	3	3.0	-		205,875	-
38	Total A&G (Account 920)		309	291	300.0	(9.0)	-2.9%	$ 6,247,183	$ (163,694)
			(a)	(a)				(b)	

39	Total A/C 920 Direct Labor Adjustment	(000's)	$ (164)
40	Add: Indirect On-Costs	(c)	11.5%
41	Direct Labor Times On-Cost Percentage		(19)
40	Total Adjustment to Normalize for Average Staffing in A&G A/C 920		$ (183)

Footnotes:

(a) Source: Staffing levels from CA-IR-465, CA-IR-27 & CA-IR-100.

(b) Source: HECO direct labor forecast from CA-IR-1 (T-10), Attachment 38.

(c)

Indirect costs:	Total A/C 920
Direct $	$ 14,428,166
Oncost $	1,661,377
Total Labor $	$ 16,089,543
Oncost %	11.5%

Source: HECO-WP-101(F) & (H).

NOTE: Adjusted to reflect Final Settlement made to CA Exhibit CA-101, Schedule C-16:

PFB = 1 Actual HC added to represent Agency Temp hired in 9/06 through 4/07 (Temp $ were unbudgeted).

PHS = 1 Actual HC added to represent 1 temp hired from 1/07 to present (revised to "8") & expanded coverage from security services company. To date, $51K of unbudgeted agency temp and contract security services cost incurred.

PFA = 1 Actual HC added. HRIS Analyst hired on 1/3/07.

PSP = 1 Actual HC added to represent 1 Agency Temp hired 12/06 through 4/07. Candidate accepted employment offer on 8/24/07.

PSM = 1 Actual HC added. Planning Analyst position filled on 1/15/07.

PVF = TY HC changed to 25 and 12/31/06 actual changed to 22. Correction of numbers.

PNP = 8 Actual HC added to eliminate labor cost adjustment. Admin Assistant hired on 1/8/07. Also, Average Test Year HC = 11, due to ramping up of additional 7 positions from 7/07 (see Updated Workpaper 1401, filed in June 2007 Update (T-14)).

PNI = 1 Actual HC added to represent 1 HECO Temp hired 1/16 through May 2007 and 1 Agency Temp from January 2007 to present.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386
PAYROLL EXPENSE (OTHER A&G)
FOR THE FORECAST 2007 TEST YEAR

LINE NO.	RA	Division	Average Staffing Calculations: Updated 2007 TY	Actual 12/31/2006	Average	Difference	Adjustment Percentage Difference	HECO Direct Labor Forecast	Direct Labor O&M Adjustment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	NARUC A/C 925								
2	PDS Note (b)	C&M-Operations	160	161	160.5	0.5	0.3%	$ 95,826	$ 299
3	PFA	Workforce & Dev-Admin	4	4	4.0	-	0.0%	2,052	-
4	PFB	Comp & Ben-Empl Benef	10	9	9.5	(0.5)	-5.0%	131	(7)
5	PQC	Corporate Communications	9	8	8.5	(0.5)	-5.6%	656	(36)
6		TOTAL A/C 925	183	182	182.5	(0.5)		98,665	256
7	NARUC A/C 926000								
8	PFA	Workforce & Dev-Admin	4	4	4.0	-	0.0%	2,850	-
9	PFB	Comp & Ben-Empl Benef	10	9	9.5	(0.5)	-5.0%	420,577	(21,029)
10	PHF	Safety,Secur-Facilities Planning	8	7	7.5	(0.5)	-6.3%	1,574	(98)
11		TOTAL A/C 926000	22	20	21.0	(1.0)		425,001	(21,127)
12	NARUC A/C 926010								
13	PEC	ITS-Customer Care	23	25	24.0	1.0	4.3%	499	22
14	PED	ITS-Development Svs	37	36	36.5	(0.5)	-1.4%	50,788	(686)
15	PEI	ITS-Infrastructure & Ops	24	22	23.0	(1.0)	-4.2%	197	(8)
16	PFA	Workforce & Dev-Admin	4	4	4.0	-	0.0%	36,923	-
17	PFB	Comp & Ben-Empl Benef	10	9	9.5	(0.5)	-5.0%	91,170	(4,559)
18		TOTAL A/C 926010	98	96	97.0	(1.0)		179,577	(5,231)
19	NARUC A/C 9301								
20	PQC	Corporate Communications	9	8	8.5	(0.5)	-5.6%	1,625	(90)
21		TOTAL A/C 9301	9	8	8.5	(0.5)		1,625	(90)
22	NARUC A/C 9302								
23	P9P	President	3	2	2.5	(0.5)	-16.7%	3,416	(569)
24	PBZ	Engineering-T&D Tech Services	8	7	8	(1)	-6.3%	397	(25)
25	PCA	Cust Svc- Admin (~~Sr. VP Ops-Adm~~	5	4	5	(1)	-10.0%	615	(62)
26	PDA	C&M-Admin	6	5	6	(1)	-8.3%	688	(57)
27	PED	ITS-Development Svs	37	36	36.5	(0.5)	-1.4%	374	(5)
28	PFA	Workforce & Dev-Admin	4	4	4.0	-	0.0%	66	-
29	PFB	Comp & Ben-Empl Benef	10	9	9.5	(0.5)	-5.0%	715	(36)
30	PQC	Corporate Communications	9	8	8.5	(0.5)	-5.6%	36,556	(2,031)
31	PRD	Sys Ops-Operating Dispatch	27	23	25	(2)	-7.4%	425	(31)
32	PSM	Forecasts & Research	10	10	10.0	-	0.0%	665	-
33	PWA	Cust Intal-Admin	12	11	11.5	(0.5)	-4.2%	9,464	(394)
34	PWX	Cust Intal-Engineering & Meter	14	12	13.0	(1 0)	-7.1%	99,775	(7,127)
35	PYF	Power Supply-Elect Engineering	12	10	11.0	(1.0)	-8.3%	3,871	(323)
36		TOTAL A/C 9301	157	141	149.0	(8.0)		157,027	(10,660)
37	NARUC A/C 932								
38	PHF	Safety,Secur-Facilities Planning	8	7	7.5	(0.5)	-6.3%	95,562	(5,973)
39	PHS	Safety,Secur-Security	10	8	9.0	(1.0)	-10.0%	6,130	(613)
40	PVL	Sup Svs - Elec & Weld	12	12	12.0	-	0.0%	41,587	-
41		TOTAL A/C 932	30	27	28.5	(1.5)		143,279	(6,586)
42	Total A&G (excluding Account 920)		499	474	486.5	(12.5)	-2.5%	$ 1,005,174	$ (43,438)
			(a)	(a)				(b)	

43	A&G (ex. A/C 920) Direct Labor Adjustment	(000's)	$ (43)
44	Add: Indirect On-Costs	(c)	13.5%
45	Direct Labor Times On-Cost Percentage		(6)
44	Total Adjustment to Normalize for Average A&G (excl. A/C 920) Staffing		$ (49)

Footnotes:

(a) Source: Staffing levels from CA-IR-465, CA-IR-27 & CA-IR-100.

(b) Source: HECO direct labor forecast from HECO-WP-101(F).

(c) Indirect costs:

Indirect costs:	Total A&G	Total A/C 920	Total Other A&G
Direct $	$ 17,084,512	$ (14,428,166)	$ 2,656,346
Oncost $	2,019,167	(1,661,377)	357,790
Total Labor $	$ 19,103,679	$ (16,089,543)	$ 3,014,136
Oncost %	11.8%	11.5%	13.5%

Source: HECO-WP-101(F) & (H).

NOTE: Adjusted to reflect Final Settlement made to CA Exhibit CA-101, Schedule C-17:

PVL Updated 2007 TY (Column C) HC decreased by 2 (from 14 to 12). Correction of error (see response to CA-IR-465).

PFA = 1 Actual HC added. Position filled on 1/3/07.

PFB = 1 Actual HC added to represent Agency Temp hired in 9/06 through 4/07 (Temp $ were unbudgeted).

PCA = Correction of Division name.

PSM = 1 Actual HC added. Planning Analyst position filled on 1/15/07.

PHS = 1 Actual HC added to represent 1 temp hired from 1/07 to present & expanded coverage from security services company. Revised to "8" in Actual column

PRD = 1 Actual HC added. Temps hired from January through present (and planned throughout the rest of year). Unbudgeted contractor costs of approximately $85K incurred to date.

Hawaiian Electric Company, Inc.
Docket No. 2006-0386

EMPLOYEE BENEFITS

Consumer Advocate Employee Benefits Adjustment (N.1)	($254,000)
Consumer Advocate Number of Employees Adjustment (N.1)	54
Average Employee Benefits Per Employee	($4,704)
HECO Number of Employees Adjustment (N.2)	22
HECO Employee Benefits Adjustment	($103,481)

N.1 Exhibit CA-101, Schedule C-22
N.2 Labor Expense Adjustment, HECO T-14

Net Headcount Reduction:	
Customer Service (HECO T-14, Attachment 1(A))	-2
T&D (HECO T-14, Attachment 1(B))	-11
A&G Account 920 (HECO T-14, Attachment 1,C)	-7
A&G Account 920 (HECO T-14, Attachment 1(D))	-2
Average Employee Count Reduction	-22

Hawaiian Electric Company, Inc.
Adjustment to Payroll Taxes from June 2007 Update
Test Year 2007

	Direct Labor (A)	Payroll Tax @ 8.18% (A) * 8.18%
Labor Adjustments:		
T&D payroll adjustment (direct labor) - Attachment 1(B)	(283)	(23)
Customer Service payroll adjustment (direct labor) - Attachment 1(A)	(85)	(7)
A&G Account 920 Payroll adjustment (direct labor)- Attachment 1(C)	(164)	(13)
Misc A&G Accounts payroll adjustment (direct labor) -Attachment 1(D)	(42)	(3)
		(46)
DSM Adjustment:		
Labor and on-cost to be recovered through surcharge	(320)	(26)
		(72)

Note: 8.18% is the payroll tax on-cost rate used for the budget for the test year estimates.

Hawaiian Electric Company, Inc.
Payroll Taxes Charged to Operations
For Test Year 2007

	Summary of Payroll Taxes Charged to Operations	2007 Test Year	Adjustment	2007 Test Year	Adjustment	2007 Update	Adjustment	2007 Settlement
1	FICA	6,394	-69	6,325	-20	6,305	-71	6,234
2	Federal Unemployment Taxes	62	-1	61	0	61	-1	60
3	State Unemployment Taxes	43	0	43	-43	0	0	0
4	Total Payroll Taxes Charged to Operations	6,499	-70	6,429	-63	6,366	-72	6,294

	Allocation of Payroll Taxes Based on Labor Dollars Charged	Test Year Payroll Taxes	Adjustment		Adjustment	Test Year Payroll Taxes	Adjustment	Test Year Payroll Taxes
5	Capital	1,123		1,123	0	1,123	0	1,123
6	Operations	6,499	-70	6,429	-63	6,366	-62	6,304
7	Others	1,358		1,358	13	1,371	0	1,371
	Total Payroll Taxes	8,980	-70	8,910	-50	8,860	-62	8,798

	Breakdown of Payroll Taxes	Payroll Taxes	Calculated Percentages	Net Flex	Net Payroll Taxes	Payroll Taxes Charged to Operations	Adjustment	Payroll Taxes Charged to Operations	Adjustment	Payroll Taxes Charged to Operations	Adjustment	Payroll Taxes Charged to Operations
8	FICA	9,026	98.38%	-190	8,836	6,394	-69.0	6,325	-20	6,305	-71.0	6,234
9	FUTA	88	0.96%	-2	86	62	-1.0	61	0	61	-1.0	60
10	SUTA	61	0.66%	-1	60	43	0.0	43	-43	0	0.0	0
11	Total Payroll Taxes	9,175	100.00%	-193	8,982	6,499	-70.0	6,429	-63	6,366	-72	6,294

Adjustments to Test Year:	Labor	Taxes	Other
Distribution Operations (Cust Svc staffing plan)	-68	-5	
903 Cust Svc staffing plan	-74	-6	
910 DSM	-664	-48	
920 HR Suites	-43	-3	
926010 HR Suites	-103	-8	
9302 AUW/CAG	-5		
932 Normalization of maint	-20		
Total Adjustments to O&M	-977	-70	0

Adjustments for Update:	Labor	total Taxes	O&M Taxes	
Adjustments per CA-IR-27 (add 2 DSM employees)	75	5	5	
Labor in Production O&M (add 5 new employees)	219	18	12	(12 O&M, 6 Billable)
Labor in Production O&M (OT decrease)	-402	-33	-33	
Engineering Retention Program	127	10	10	
Comm Svc VP retire (Ref: HECO-1304)	-166	-14	-14	
Distribution Ops (added Deferred OMS labor)	90	7	0	(No O&M, Deferred)
Change SUTA rate and base		-43	-43	
		-50	-63	
			-20	

Adjustments for 1st Proposal:	Labor (All)	O&M Labor	total Taxes	O&M Taxes	150 Labor
T&D Payroll expense adjustment	-316	-316	-23	-23	-283
Customer Service Payroll expense adjustment	-51	-51	-4	-4	-51
Customer Service remove DSM employees (to IRP)	-301	-301	-22	-22	-267
A&G Other Payroll expense adjustment	-48	-48	-3	-3	-42
A&G (920) Payroll expense adjustment	-134	-134	-10	-10	-120
	-850	-850	-62	-62	-763

Adjustments for Counter Proposal:	Labor (All)	O&M Labor	total Taxes	O&M Taxes	150 Labor
Customer Service Payroll expense adjustment	-34	-34	-3	-3	-34
Customer Service remove DSM employees (to IRP)	-60	-60	-4	-4	-53
A&G (920) Payroll expense adjustment	-49	-49	-3	-3	-44
	-143	-143	-10	-10	-131

HECO
DOCKET NO. 2006-0386
2007 Rate Case Settlement -- Deferred Taxes related to CWIP and TCI

Option to include DIT related to AFUDC in CWIP and Regulatory Asset for AFUDC Equity Gross Up (related to CWIP) net of DIT

Adjustment to Rate Base as of Update June 2007
Increase (Decrease) Rate Base

	Option #1
Balances at 12/31/06	
Deferred Taxes on AFUDC in CWIP	(7,796,517)
Deferred Taxes on TCI related to CWIP	
Reg Asset for AFUDC Equity Gross Up related to CWIP	4,054,635
Deferred Taxes on Reg Asset	(1,577,646)
Total	(5,319,528)
Balances at 12/31/07	
Deferred Taxes on AFUDC in CWIP	(8,517,728)
Deferred Taxes on TCI related to CWIP	
Reg Asset for AFUDC Equity Gross Up related to CWIP	4,565,049
Deferred Taxes on Reg Asset	(1,776,247)
Total	(5,728,926)
2007 Average Balance	
Deferred Taxes on AFUDC in CWIP	(8,157,123)
Deferred Taxes on TCI related to CWIP	-
Reg Asset for AFUDC Equity Gross Up related to CWIP	4,309,842
Deferred Taxes on Reg Asset	(1,676,947)
Total	(5,524,227)

Hawaiian Electric Company, Inc.
Working Cash Study
O&M Non-Labor Payment Lag

File: S:\RegulatoryAffairs\HECO TY 2007 Rate Case\Settlement - All Parties\T-17\[HECO T-17 Att 1 Settlement.xls]Non-Labor O&M
Source: Per Supporting Worksheets

	Test Year Expense ($000's) Note A	% of Total	Total Payment Lag Days	Weighted Average
Pension Expense [1]		0%		days
OPEB Expense [2]	$4,636	4%	85 HECO-WP-1706, p. 33-36	4 days
System Devel. Costs Amortization [3]	$158	0%	30	days
Regulatory Commission Expense [4]	$320	0%	30	days
Waiau Water Well Amortization [5]	$296	0%	30	days
Kahe Unit 7 Amortization [5]	$321	0%	30	days
Emission Fees [5]	$691	1%	306	2 days
EPRI Dues [6]	$1,608	2%	-7	days
Other Non-Labor O&M [7]	$97,973	92%	30	28 days
	$106,003	100%		
O&M Non-Labor Payment Lag				**34 days**

NOTE: Totals may not add exactly due to rounding.

Note A

[1] Pension expense estimate based on 2007 Pension Accrual of $17,710k (per June 2007 Update HECO T-12) x 73% (based on 2006 % of Employee Benefits charged to O&M expense) = $12,929k. For purposes of settlement, the Parties agree to exclude pension expense from the calculation of the O&M non-labor payment lag days and from the working cash calculation.

[2] OPEB expense estimate based on 2007 OPEB expense of $6,350k (per June 2007 Update HECO T-12) x 73% (based on 2006 % of Employee Benefits charged to O&M expense). Includes $1,302k of SFAS 106 Reg. Asset amortization.

[3] June 2007 Update, HECO T-10, Attachment 5. Also see Note B.

[4] June 2007 Update, HECO T-13, page 6. Also see Note B.

[5] HECO T-6 or June 2007 Update, HECO T-6. Also see Note B.

[6] EPRI Dues per HECO-1304

[7] Other Non-Labor O&M = Total O&M Non-Labor expense of $118,932k, less pension expense of $12,929k and less other items noted above.

Note B

For purposes of settlement, the Parties agree to include the amortization items in the working cash calculation and apply the "other" non-labor O&M payment lag day to the amortization items.

Hawaiian Electric Company, Inc.

Composite Embedded Cost of Capital
Test Year 2007 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	WP Series Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	WP-1902	$ 38,971	3.08%	5.00%	0.15%
Long-Term Debt	WP-1903	480,727	38.01%	6.09%	2.31%
Hybrid Securities	WP-1904	27,556	2.18%	7.47%	0.16%
Preferred Stock	WP-1905	20,586	1.63%	5.51%	0.09%
Common Equity	WP-1906	696,825	55.10%	10.70%	5.90%
Total Capitalization		$1,264,666	100.00%		8.62%
Estimated 2007 Test Year Composite Cost of Capital					**8.62%**

Totals may not add exactly due to rounding.

Proposed Settlement Allocation of Revenue Increase

Step 1: Initial Allocation

Rate Class	% of Increase $
Schedule R	35.71%
Schedule G	6.65%
Schedule J	25.37%
Schedule H	0.61%
Schedule PS	9.10%
Schedule PP	20.50%
Schedule PT	1.47%
Schedule F	0.59%
Total	100.00%

Step 2: Reassignment of Revenues in Schedule P to Adjust
for Proposed Billing Credit for Schedule PP Customers Directly Served
from a Dedicated Substation

Sch PP Directly Served	-$5,520,590	
Sch PP Not Directly Served	$2,972,625	
Sch PS	$2,213,478	
Sch PT	$334,487	
Total	$0	
Sch PP Directly Served		
Billing kW	1,698,643	HECO-WP-2016, page 119
Billing credit per kW	-$3.25	
Total Billing Credit	-$5,520,590	
Billing kW Schedule PP	4,163,006	HECO-WP-2016, page 119
Billing kW Schedule PS	1,881,703	HECO-WP-2016, page 106
Billing kW Schedule PT	284,351	HECO-WP-2016, page 140

Assignment of Billing Credit to Rate Schedules
$1.75 Assigned to Schedule PP, $1.50 Assigned to Schedule PS and PT based on kWb

Proposed Settlement Rate Design:

Schedule R

Customer Charge	- Single Phase	$8.00 per month
Customer Charge	- Three Phase	$17.00 per month
Minimum Charge	- Single Phase	$16.00 per month
Minimum Charge	- Three Phase	$22.00 per month

Non-Fuel Energy Charge Tiers
0 – 350 kWh
351 – 1200 kWh
Over 1200 kWh

Customers eligible under the LIHEAP provision pay for non-fuel energy for all kWh at the rate set for the 0-350 kWh tier.

The proposed Non-Fuel Energy Charges will be adjusted to achieve the total revenues assigned to Schedule R.

Schedule G

Customer Charge	- Single Phase	$30.00 per month
Customer Charge	- Three Phase	$55.00 per month
Minimum Charge	- Single Phase	$30.00 per month
Minimum Charge	- Three Phase	$55.00 per month

Primary Supply Voltage Service Discount

-2.1% of energy charges for primary location
- 0.5% of energy charges for secondary location

The proposed Energy Charge will be adjusted to achieve the total revenues assigned to Schedule G.

Schedule J

Customer Charge - Single Phase $50.00 per month
Customer Charge - Three Phase $70.00 per month

Demand Charge $ 9.78 per billed kW

Supply Voltage Delivery Discount

-2.9% of demand and energy charges for transmission primary
-2.4% of demand and energy charges for transmission secondary
-2.1% of demand and energy charges for distribution primary
-0.5% of demand and energy charges for distribution secondary

Network Service Adjustment +0.9% of demand and energy charges

Each energy charge tier will be adjusted by the same amount in cents per kWh. The proposed Energy Charges will be adjusted to achieve the total revenues assigned to Schedule J.

Schedule H

Customer Charge - Single Phase $25.00 per month
Customer Charge - Three Phase $60.00 per month

Demand Charge $10.00 per billed kW

The proposed Energy Charge will be adjusted to achieve the total revenues assigned to Schedule G.

Schedule PS

Customer Charge $350.00 per month

Demand Charge	0-500 kW	$17.94 per billed kW
Demand Charge	501-1500 kW	$17.31 per billed kW
Demand Charge	over 1500 kW	$16.06 per billed kW

Each energy charge tier will be adjusted by the same amount in cents per kWh. The proposed Energy Charges will be adjusted to achieve the total revenues assigned to Schedule PS.

Schedule PP

Customer Charge $400.00 per month

Demand Charge	0-500 kW	$17.69 per billed kW
Demand Charge	501-1500 kW	$17.06 per billed kW
Demand Charge	over 1500 kW	$15.81 per billed kW

Billing Demand Credit for Customers
Directly served by a Dedicated Substation - $3.25 per billed kW

Secondary Metering Adjustment 0.2825 cents per kWh

Each energy charge tier will be adjusted by the same amount in cents per kWh. The proposed Energy Charges will be adjusted to achieve the total revenues assigned to Schedule PP.

Schedule PT

Customer Charge $400.00 per month

Demand Charge	0-500 kW	$17.50 per billed kW
Demand Charge	501-1500 kW	$16.88 per billed kW
Demand Charge	over 1500 kW	$15.63 per billed kW

Secondary Metering Adjustment 0.5% of demand and energy charges

Each energy charge tier will be adjusted by the same amount in cents per kWh. The proposed Energy Charges will be adjusted to achieve the total revenues assigned to Schedule PT.

Schedule F

Customer Charge $20.00 per month

Secondary Metering Adjustment + 1.5%
Loss Factor for Unmetered Service Billing Demand + 1.02

Each energy charge tier will be adjusted by the same amount in cents per kWh. The proposed Energy Charges will be adjusted to achieve the total revenues assigned to Schedule F

Schedule TOU-R

Customer Charge	- Single Phase	$9.50 per month
Customer Charge	- Three Phase	$17.50 per month
Minimum Charge	- Single Phase	$17.50 per month
Minimum Charge	- Three Phase	$22.50 per month

Energy Charges:

Calculated in the same manner and at the same rates as the proposed Schedule R, with the following time-of-use energy rate adjustments

Priority Peak Period kWh use	+ 5.0 cents per kWh
Mid-Peak Period kWh use	+ 2.0 cents per kWh
Off-Peak Period kWh use	-3.5 cents per kWh

Priority Peak Period	5pm to 9pm, Monday through Friday
Mid-Peak Period	7am to 5pm, Monday through Friday 5pm to 9pm, Saturday, Sunday, Holidays
Off-Peak Period	9pm to 7am, Daily 7am to 5pm, Saturday, Sunday, Holidays

Holidays are the observed days for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Service is limited to a maximum of 1,000 customers until the new Customer Service Information System is implemented.

Schedule TOU-C

Non-Demand Service

Customer Charge	- Single Phase	$30.00 per month
Customer Charge	- Three Phase	$55.00 per month

Minimum Charge	- Single Phase	$30.00 per month
Minimum Charge	- Three Phase	$55.00 per month

Energy Charges:

Priority Peak Period kWh use	Sch G energy Charge + 5.0 cents per kWh
Mid-Peak Period kWh use	Sch G energy Charge + 2.0 cents per kWh
Off-Peak Period kWh use	Sch G energy Charge - 5.0 cents per kWh

Demand Service

Customer Charge	- Single Phase	$50.00 per month
Customer Charge	- Three Phase	$70.00 per month

Minimum Charge Customer Charge + Demand Charge

Demand Charge

$17.28 per billed kW if maximum demand occurs in priority peak period
$ 9.78 per billed kW if maximum demand occurs in mid-peak period

Energy Charges:

Priority Peak Period kWh use	Avg Sch J energy Charge + 5.0 cents per kWh
Mid-Peak Period kWh use	Avg Sch J energy Charge + 2.0 cents per kWh
Off-Peak Period kWh use	12.0000 cents per kWh

Priority Peak Period	5pm to 9pm, Monday through Friday
Mid-Peak Period	7am to 5pm, Monday through Friday 7am to 9pm, Saturday and Sunday
Off-Peak Period	9pm to 7am, Daily

Schedule U

Customer Charge $350.00 per month

Minimum Charge Customer Charge + Demand Charge

Demand Charge

$22.50 per billed kW if maximum demand occurs in priority peak period
$19.50 per billed kW if maximum demand occurs in mid-peak period

Energy Charges:

On-Peak Period kWh use	Avg Sch PS energy Charge + 2.0 cents per kWh
Off-Peak Period kWh use	12.0000 cents per kWh

On-Peak Period	7am to 9pm, Daily
Off-Peak Period	9pm to 7am, Daily